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In The

Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,
Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

Petition for Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

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QUESTION PRESENTED

Where Congress has declared that natural gas local distribution companies are subject only to state regulation, may the Federal Energy Regulatory Commission assert control over the allocation and sale of capacity rights by those companies to consumers within the state?

PARTIES TO THE PROCEEDING

The parties to the proceeding below were:

Federal Energy Regulatory Commission (Respondent)

Alabama Gas Corporation (Intervenor)

Algonquin Gas Transmission Company (Intervenor)

Allied Signal Inc. (Intervenor)

American Forest & Paper Association (Petitioner)

American Public Gas Association (Petitioner)

Amoco Production Company (Intervenor)

Anadarko Petroleum Corporation (Intervenor)

ANR Pipeline Company (Intervenor)

Arcadian Fertilizer (Petitioner)

Arco Natural Gas Marketing (Intervenor)

Arco Oil & Gas Company (Intervenor)

Arizona Electric Power Cooperative Inc. (Petitioner)

Arizona Public Service Company, *et al.* (Petitioner)

Asarco, Inc., Cyprus Miami Mining Corporation, and Magma Copper Company (Petitioner)

Associated Gas Distributors (Petitioner)

Associated Natural Gas Company (Petitioner)

Atlanta Gas Light Company (Petitioner)

Baltimore Gas & Electric Company (Petitioner)

Bay State Gas Company, *et al.* (Intervenor)

Board of Water, Gas & Light Commissioners, Albany, Georgia (Intervenor)

Brooklyn Union Gas Company (Intervenor)

Canadian Association of Petroleum Producers, *et al.* (Intervenor)

Carnegie Natural Gas Company (Petitioner)

Chattanooga Gas Company (Petitioner)

Cascade Natural Gas Corporation (Intervenor)

Chevron, U.SA, Inc. (Intervenor)

Cincinnati Gas & Electric Company, *et al.* (Intervenor)

Citizens Gas & Coke Utility (Petitioner)

City of Hamilton, Ohio (Petitioner)

CNG Transmission Corporation (Petitioner)

Colorado Interstate Gas Company (Petitioner)

Colorado Springs Utilities (Petitioner)

Columbia Gas Distribution Companies (Intervenor)

Columbia Gas Transmission Corporation (Intervenor)

Conoco, Inc. (Intervenor)

Consolidated Edison Company of New York, Inc. (Petitioner)

Dakota Gasification Company (Intervenor)

Dayton Power & Light Company (Intervenor)

Destec Energy, Inc. (Intervenor)

East Ohio Gas Company, *et al.* (Intervenor)

East Tennessee Group (Petitioner)

East Tennessee Natural Gas Company (Intervenor)

Elizabethtown Gas Company, an Operating Division of NUI Corporation (Petitioner)

El Paso Natural Gas Company (Intervenor)

Enron Oil & Gas Marketing, Inc. (Intervenor)

Enserch Development Corporation (Petitioner)

Equitrans, Inc. (Petitioner)

Exxon Corporation (Intervenor)

Florida Cities (Intervenor)

Florida Gas Transmission Co. (Intervenor)

Foothills Pipelines Ltd. (Intervenor)

Fort Pierce Utilities Authority and the City of Vero Beach, Florida (Intervenor)

Fuel Managers Association (Intervenor)

Georgia Industrial Group (Petitioner)

Great Lakes Transmission Ltd. (Intervenor)

Hadson Gas Systems, Inc. (Petitioner)

Illinois Commerce Commission (Petitioner)

Illinois Power Company (Petitioner)

Indiana Gas Company (Petitioner)

Interstate Natural Gas Association of America (Intervenor)

Joint State Commissions and Consumer Advocates (Petitioner)

KN Energy, Inc. (Intervenor)

Kern River Gas Transmission Company (Petitioner)

Koch Gateway Pipeline Company (Petitioner)

Laclede Gas Company (Petitioner)

Long Island Lighting Company (Petitioner)

Louisville Gas & Electric Company (Petitioner)

Maryland Office of People's Counsel (Petitioner)

Maxus Exploration Company and Maxus Gas Marketing Company (Intervenor)

Memphis Light, Gas and Water Division (Petitioner)

Meridian Oil Inc. (Petitioner)

Michigan Consolidated Gas Company (Intervenor)

Midland Cogeneration Venture Limited (Petitioner)

Minnesota Public Utility Commission and Minnesota Department of Public Service (Intervenor)

Mississippi River Transmission Corporation (Intervenor)

Missouri and Kansas Gas Users (Intervenor)

Missouri Public Service Commission, *et al.* (Petitioner)

Mitchell Energy Corporation (Intervenor)

Mobile Gas Service Corporation, *et al.* (Intervenor)

Mobile Natural Gas, Inc. (Intervenor)

Montana Public Service Commission, Public Utilities Commission of South Dakota and Montana Consumer Counsel (Petitioner)

Mountaineer Gas Company (Petitioner)

National Association of State Utility Consumer Advocates (Petitioner)

National Association of Gas Consumers (Intervenor)

National Fuel Gas Supply Corporation (Intervenor)

Natural Gas Clearinghouse (Intervenor)

Natural Gas Pipeline Company of America (Intervenor)

New Jersey Board of Regulatory Commissioners (Petitioner)

New Jersey Natural Gas Company (Petitioner)

New York State Electric & Gas Corporation (Intervenor)

New England Power Company (Petitioner)

Northern Indiana Public Service Company (Petitioner)

Niagara Mohawk Power Corporation (Petitioner)

Noram Energy Corporation (Petitioner)

North Carolina Natural Gas Company and Public Service Commission of North Carolina (Intervenor)

Northeast Energy Associates and New Jersey Energy Associates (Intervenor)

Northern Border Pipeline Company (Intervenor)

Northern Distributor Group (Intervenor)

Northern States Power Company (Minn.), *et al.* (Intervenor)

Northern Natural Gas Company, *et al* (Intervenor)

Northwest Alaskan Pipeline Company (Petitioner)

Ocean State Power, *et al.* (Petitioner)

Office of the Consumers' Counsel, State of Ohio (Petitioner)

Orange and Rockland Utilities, Inc. (Petitioner)

Ozark Gas Transmission System (Petitioner)

Pacific Gas & Electric Company (Petitioner)

Pacific Interstate Transmission Company, *et al.* (Intervenor)

Pan-Alberta Gas, Ltd. (Intervenor)

Panhandle Customer Group (Intervenor)

Panhandle Eastern Pipe Line Company (Intervenor)

Panhandle Trading Company (Intervenor)

Pennzoil Exploration & Production Company and Pennzoil Gas Marketing Company (Intervenor)

PEPCO Energy (Petitioner)

Pennsylvania Office of Consumer Advocate (Petitioner)

Pennsylvania Public Utility Commission, *et al.* (Petitioner)

Peoples Gas System, Inc. (Intervenor)

Peoples Natural Gas Company (Petitioner)

Piedmont Natural Gas Company (Petitioner)

Philadelphia Electric Company (Petitioner)

Phillips Petroleum Company, *et al.* (Intervenor)

Plains Petroleum Operating Company (Petitioner)

Process Gas Consumers Group, *et al.* (Intervenor)

Producer-Marketing Transportation Group (Petitioner)

ProGas, Ltd. (Petitioner)

Public Service Commission of the Commonwealth of Kentucky (Petitioner)

Public Service Commission of Nevada (Intervenor)

Public Service Commission of the State of New York (Petitioner)

Public Service Commission of West Virginia, Consumer Advocate Division (Petitioner)

Public Service Commission of Wisconsin (Petitioner)

Public Service Electric & Gas Company (Intervenor)

Public Utilities Commission of the State of California (Petitioner)

Rochester Gas & Electric Company (Intervenor)

Shell Gas Trading Company (Intervenor)

South Jersey Gas Company (Intervenor)

South Carolina Pipeline Corporation (Intervenor)

Southern Natural Gas Company (Intervenor)

Southwest Gas Corporation (Petitioner)

State of Louisiana (Petitioner)

State of Indiana, Office of Utility Consumer Counselor (Petitioner)

Tenneco Gas, Inc. (Intervenor)

Tennessee Gas Pipeline Company (Intervenor)

Tennessee Small General Service and Columbia Small Customer Group (Intervenor)

Tennessee Valley Municipal Gas Association (Petitioner)

Texaco, Inc. (Intervenor)

Texas Eastern Transmission Corporation, *et al.* (Intervenor)

TransCanada Pipelines Limited (Intervenor)

Transcontinental Gas Pipe Line Corporation (Intervenor)

Transwestern Pipeline Company (Intervenor)

Trunkline Gas Company (Intervenor)

T.W. Phillips Gas & Oil Company (Intervenor)

UGI Utilities, Inc. (Intervenor)

Union Pacific Fuels, Inc. (Intervenor)

United Cities Gas Company (Intervenor)

United Distribution Companies (Petitioner)

Vastar Resources, Inc. and Vastar Gas Marketing, Inc. (Intervenor)

Virginia Electric & Power Company (Petitioner)

Washington Gas Light Company (Intervenor)

Williams Gas Marketing Company (Petitioner)

Williams Natural Gas Company (Petitioner)

Williston Basin Interstate Pipeline Company (Petitioner)

Windward Energy and Marketing Company (Intervenor)

Wisconsin Distributor Group (Petitioner)

CORPORATE DISCLOSURE STATEMENT

Petitioner Associated Gas Distributors (AGD) is a trade association incorporated under the laws of Delaware. The member companies of AGD are local natural gas distribution utilities. AGD does not have any parent companies or subsidiaries.

Petitioner Atlanta Gas Light Company (Atlanta) is a corporation organized and existing under the laws of the State of Georgia and is engaged primarily in the purchase, sale and distribution of gas within Georgia. Atlanta has no parent companies or subsidiaries (other than wholly-owned subsidiaries).

Petitioner Chattanooga Gas Company (Chattanooga) is a public utility engaged in the distribution of natural gas in the City of Chattanooga, Tennessee, and surrounding territory. Chattanooga is a wholly-owned subsidiary of Atlanta and has no subsidiaries.

Petitioner Northern Indiana Public Service Company (Northern Indiana) is a public utility incorporated in the State of Indiana and engages in supplying natural gas and electric energy to the public in the Northern third of Indiana. Northern Indiana is a wholly-owned subsidiary of NIPSCO Industries, Inc., an energy-based holding company.

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Associated Gas Distributors, Atlanta Gas Light Company, Chattanooga Gas Company, and Northern Indiana Public Service Company respectfully petition for a writ of certiorari to review the judgment of the United States Court of Appeals for the District of Columbia Circuit in this case.

OPINIONS BELOW

The opinion and judgment of the Court of Appeals (reprinted in Pet. App. A) is reported at 88 F.3d 1105 (D.C. Cir. 1996), and was amended in relevant part on October 29, 1996 (reprinted in Pet. App. F). The orders of the Federal Energy Regulatory Commission, Orders 636, 636-A, 636-B, and 636-C (reprinted in Pet. App. B, C, D, and E, respectively) are reported at III FERC ¶ 30,939 (1992), III FERC ¶ 30,950 (1992), 61 FERC ¶ 61,272 (1992), and 62 FERC ¶ 61,007 (1993), respectively.

STATEMENT OF JURISDICTION

On July 16, 1996, the Court of Appeals affirmed in part and remanded in part the orders of the Federal Energy Regulatory Commission (FERC) known as Orders 636, 636-A, 636-B, and 636-C (collectively, Order 636). The Court of Appeals' July 16 opinion upheld the validity of the portion of Order 636 challenged by this Petition. On October 29, 1996, the Court of Appeals denied a timely petition for rehearing and suggestion for rehearing *en banc* submitted by certain of these Petitioners. The jurisdiction of this Court is invoked pursuant to 28 U.S.C. § 1254(1).

STATUTORY PROVISIONS INVOLVED

Section 1(b) of the Natural Gas Act, 15 U.S.C. § 717(b), provides:

> The provisions of this chapter shall apply

> to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

Section 1(c) of the Natural Gas Act, 15 U.S.C. § 717(c), provides:

> The provisions of this chapter shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this chapter by this subsection are declared to be matters primarily of local concern and subject to regulation by the several States. A certification from such State commission to the Federal Power Commission that such State commission has regulatory jurisdiction

over rates and service of such person and facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction.

STATEMENT OF THE CASE

This case is about FERC's effort, in Order 636, to preempt state regulatory authority over "capacity sales" by state-regulated local distribution companies to end-user customers within the State. The portion of the Court of Appeals opinion addressing the issue is at 88 F.3d at 1148-53; Pet. App. A, 71a-82a, *as amended by* Pet. App. F, 1001a-1002a.[1] To understand the issue, and the flaws in the Court of Appeals' reasoning, it is necessary to provide some regulatory and historical background.

A. The Framework Of State And Federal Authority Under The Natural Gas Act

The natural gas industry is functionally separated into three segments: production, transportation, and distribution. Traditionally, a producer extracted natural gas from an underground reservoir and sold it to a pipeline company. The pipeline company then transported the gas and re-sold it to a local distribution company (LDC). The LDC, in turn, distributed the gas and sold it at retail to residential, commercial, and industrial gas consumers. 88 F.3d at 1122; Pet. App. A at 6a.

With the Natural Gas Act (NGA) of 1938, the Federal Power

1. An appendix containing the opinion of the court of appeals and opinions on rehearing, as well as the several, lengthy FERC orders that give rise to those opinions, is being filed jointly by the several petitioners for writ of certiorari of the court of appeals' decision. Citations in this Petition are to that appendix (Pet. App). The opinion below is also reported at 88 F.3d 1105 (D.C. Cir. 1996), although it does not include the amendment to the decision reflected in Pet. App. F. Parallel citations to the reported opinion are also used in the body of this Petition.

Commission, predecessor of the Federal Energy Regulatory Commission, was given authority over sales for resale in interstate commerce and over interstate transportation of gas, leaving regulation of local distribution and retail gas utility service to the States. 15 U.S.C. § 717(b). Federal authority was intended to fill a regulatory gap created by decisions of this Court under the "dormant Commerce Clause" precluding the States from regulating interstate transportation and wholesale sales of natural gas. *See* 88 F.3d at 1122, Pet. App. A, 7a; *see also Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377-80 (1983); *Panhandle Eastern Pipe Line Co. v. Pub. Serv. Comm'n of Indiana*, 332 U.S. 507, 514-21 (1947).

While the NGA assigned to a federal agency the role of filling the regulatory gap created by perceived constitutional limits on state power, all existing, state regulatory authority was preserved, free from federal intrusion. The NGA has from its inception expressly provided that neither the "local distribution" of natural gas nor the facilities used for such distribution were subject to the provisions of that law. 15 U.S.C. § 717(b).

Thus, the NGA contemplates a clear division of state and federal authority, with the States and the federal government occupying distinct regulatory spheres. The core, around which the federal government's authority filled in, was the traditional state authority over the relationship between local distribution companies and their in-state customers. The NGA "was designed to supplement state power and to produce a harmonious and comprehensive regulation of the industry. Neither state nor federal regulatory body was to encroach upon the jurisdiction of the other." *Federal Power Comm'n v. Panhandle Eastern Pipe Line Co.*, 337 U.S. 498, 513 (1949). The boundaries established by the NGA "take 'no authority from State commissions' and [are] 'so drawn as to complement *and in no*

manner usurp State regulatory authority.' " *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 610 (1944) (emphasis added) (quoting H. Rep. No. 709, 75th Cong., 1st Sess. p. 2).

B. *FPC v. East Ohio Gas* And The 1954 Hinshaw Amendment

This "walling off" of the area of traditional state authority over local distribution and local distribution companies from federal intrusion was reinforced in 1954 with an amendment to the NGA. This amendment (the "Hinshaw amendment" or "Hinshaw exemption," 15 U.S.C. § 717(c)) now helps to define the limit of FERC authority and the scope of authority reserved to the States. It specifies that certain entities subject to state regulation are *exempt* from federal regulation. It specifically provides, *inter alia*, that the NGA "shall not apply to any person engaged in . . . the transportation in interstate commerce or the sale in interstate commerce for resale," provided that certain conditions are met, most notably the condition that the entity is subject to state regulatory authority. *Id.* "The matters *exempted* from the provisions of this [Act] . . . are hereby declared to be matters primarily of local concern and subject to regulation by the several States."[2] *Id.* (emphasis added).

The Hinshaw amendment was a congressional response to a decision of this Court. In *Federal Power Commission v. East Ohio Gas Company*, 338 U.S. 464 (1950), the Court examined the scope of federal authority under Section 1(b). Finding the power the FPC was exercising to fall within the terms of the

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2. The traditional regulation of LDC services to local consumers served a variety of purposes chosen by the state government as appropriate for its citizens. While these purposes generally included economic protection of consumers from the market power of a monopoly-like provider of a basic utility service, they also served a wide range of other objectives. *See Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 634-38 (1944).

portion of Section 1(b) describing the scope of federal power, the Court treated the portion of Section 1(b) that preserves traditional state authority as mere "surplusage." 338 U.S. at 470-71. If the regulation fell within the affirmative grant of authority to the FPC over a "'natural-gas company,' no state can interfere with federal regulation." 338 U.S. at 473.

The Court acknowledged that the NGA was intended to grant the federal government authority over *only* "those companies which states could not regulate." 338 U.S. at 471. The Court concluded, however, that in determining what the States could *not* regulate, it was necessary to refer to decisions of the Court immediately preceding enactment of the NGA. Those cases had taken an extremely broad view of the (dormant) Commerce Clause and thus a very narrow view of permissible exercises of state power. The Court held that the constitutional power reserved to the States by the NGA was to be defined under these "prior constitutional decisions" and *not* by the far broader power that the States were by then acknowledged to possess. 338 U.S. at 471-72.

Justices Jackson and Frankfurter dissented. 338 U.S. at 476. They emphasized that East Ohio Gas Company is "an all-Ohio company, deriving income solely from distributing gas directly to Ohio consumers," and that the "Ohio State Commission. . . . is able to supervise and regulate this utility completely and continuously." 338 U.S. at 477. In light of the common understanding that Congress sought "to complement and in no manner usurp State regulatory authority," *id.* at 479 (quoting *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. at 610), the dissenters would have held that the State's power over East Ohio Gas left no room for federal regulation. As to the notion that power reserved to the States was defined by prior cases rather than current law, the dissenters noted that the Court had *not* provided an accurate description of the Court's own prior rulings on the scope of the dormant Commerce Clause.

Moreover, the dissenters found no basis for believing that when Congress commanded respect for state authority under Section 1(b), it meant the scope of the States' constitutional authority as declared in prior cases, rather than that constitutional authority as it actually exists — at least, as currently understood. 338 U.S. at 480-81. The "gap" in state regulatory authority which the NGA sought to fill with federal power concerned the States' inability to regulate wholesale sales. 338 U.S. at 483. Because federal power was, at bottom, a gap-filler, the dissenters asserted that the scope of federal power could only be understood by first identifying the power that the States could constitutionally exercise and which Congress reserved to them.

With the Hinshaw amendment, Congress overrode the conclusion reached by the majority in *East Ohio Gas* and sought to restore the original understanding of the Act, as better reflected in the dissent. Section 1(c) of the NGA reserved *to the States* a distinct area of state regulatory authority. Thus, LDCs regulated by state commissions were declared *exempt* from the Act and off-limits to federal regulation.

Following enactment of the Hinshaw exemption, a large number of local distribution companies filed applications to the Federal Power Commission for declarations of exemption; such applications routinely were granted. Typically, the declarations of exemption included a finding that the local distribution company was subject to regulation by the State Commission and, as such, was "exempt from the provisions of the Natural Gas Act and the orders, rules and regulations of the Commission issued pursuant thereto." *See, e.g., Atlanta Gas Light Company*, 14 F.P.C. 1156, 1157 (1955).

Pursuant to these principles, FERC has historically regulated sales for resale of natural gas *to LDCs*; state commissions have regulated LDCs' natural gas sales and services within their local, intrastate market areas.

C. FERC's Restructuring Of Natural Gas Markets By Unbundling Pipeline Services

In Order 636, FERC acted to complete a process whereby the regulated services of interstate pipelines would be "unbundled" or "separated," changing the way that natural gas and related transportation and distribution services had historically been sold. "Unbundling" meant that natural gas would no longer be sold by pipelines to LDCs "as delivered" — with the costs of production, transportation and the gas itself bundled into the purchase price of the gas sold. Rather, pipelines would have to sell "transportation" separately. 88 F.3d at 1126; Pet. App. A, 16a-17a.

These FERC-promoted changes in the market structure required a shift in the traditional market role of pipelines and other industry participants. Pipelines, for example, generally withdrew from the gas sales business and became providers of transportation services only. LDCs and certain of their traditional customers began to acquire gas supplies directly from producers or marketers, rather than pipelines, and to arrange for transportation to their facilities.

As a result of their customers' access to separate, unbundled gas supplies, LDCs were also placed in the position of providing transportation of natural gas, rather than "bundled" gas sales, to certain of their traditional customers.[3] In lieu of their

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3. An October 24, 1996 report published by the American Gas Association under the title "Providing New Services to Residential Customers: A Summary of Pilot Programs and Unbundling Initiatives" contains the following introductory statement:

> Over the last several years, local distribution companies (LDCs) have offered customers behind the city-gate an increasing array of options and services.

(Cont'd)

traditional sales of gas, LDCs provided services to these in-state customers in the form of (1) local transportation service of the customers' gas through the LDCs' distribution system; *and* (2) assignment to customers of some portion of the LDCs' own upstream interstate pipeline service rights to be used to move

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(Cont'd)

> These services have included varying degrees of transportation, storage and balancing services as well as access to upstream pipeline capacity. These services have provided industrial and commercial customers with the opportunity to purchase supplies in the marketplace from a variety of suppliers. As a result, competition created in these markets has led to significant cost savings for the customer and efficiency improvements for the natural gas industry. . . .
>
> Providing unbundling services to the residential customer poses a host of questions for LDCs, state regulators, marketers looking to serve the residential market, as well as residential customers themselves. Issues such as designing and administering customer aggregation programs, developing new contractual relationships with marketers, potentially redefining the utility's obligation to serve and the resulting costs of that service and designing new balancing services must be considered. In addition, marketing rules and regulations, the allocation of upstream pipeline and storage capacity, and the collection/administration of social costs must be addressed in developing a residential transportation program.
>
> This issue brief has identified sixteen states where either residential pilot programs or broader customer choice programs are being implemented. Fourteen LDCs in ten states have developed residential pilot programs. These pilots, in aggregate, will provide customer choice to over 200,000 households.

the customers' gas from the gas seller's facilities to the LDCs' distribution system. This latter feature of LDC transportation service has come to be called an LDC's "capacity release" or "capacity assignment." Because it involves LDCs' gas service to their traditional in-state customers, it has been regulated by the state commissions.[4]

D. FERC's Assertion Of Jurisdiction Over LDCs' Capacity Sales In Order 636

As part of its overall assertion of authority over the "restructuring" of the natural gas industry, FERC's Order 636 declared that, in the situation described above, the LDC's release or assignment of some of its pipeline capacity rights to its local customer was subject to FERC's overall plan of controlling the sale and resale of pipeline capacity. Accordingly, FERC held that an assigning LDC should be issued a transportation certificate under NGA Section 7 and its charges for this capacity assignment should, *inter alia*, be controlled (not by state law, but rather) by a FERC-determined rate ceiling.

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4. *See, e.g.*, Report and Order in re: *In the Matter of Laclede Gas Company's Tariff Sheets* (Mo. PSC, Aug. 28, 1996); Order in re: *In the Matter of the Regulation of the Purchased Adjustment Clause Contained Within the Rate Schedules of the East Ohio Gas Company and Related Matters* (Oh. PUC, Apr. 25, 1996); Order in re: *Proceeding on Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Market* (NY PUC, Mar. 28, 1996); Order in re: DPU 93-141-A (Mass. DPU, Feb. 14, 1996); Order in re: *Petition of Northern Indiana Public Service Company for Approval of Changes in its Gas Cost Adjustment Mechanism* (Ind. Util. Reg. Comm., Dec. 28, 1995); Order Approving Stipulation in re: *In the Matter of Accounting for Secondary Market Transactions by Natural Gas Local Distribution Companies* (N.C. Util. Comm., Dec. 27, 1995); Decision and Order in re: *New Jersey Natural Gas Company Compliance Filing for Unbundling of Natural Gas Services* (N.J. BPU, Oct. 19, 1994).

E. Petitioners

Petitioner Associated Gas Distributors (AGD) is a trade association composed largely of local distribution companies regulated by state commissions and engaged in the business of distributing and selling gas to commercial and residential consumers, typically within a given state. AGD's member companies operate in 18 states and the District of Columbia. AGD is joined in this Petition by three individual LDCs, each of which is acknowledged by FERC to come within the terms of the Hinshaw exemption.[5] As such, each is regulated by the States in which they operate and not by FERC. Their customers have purchased gas and need to have it transported to them, and naturally turn to LDCs for that service. The LDCs would, in turn — as they have always done — supply the transportation service, both through their own intrastate lines and through "capacity" that the LDCs have under contract with interstate pipelines. Under Order 636, the latter portion of the service that the LDCs would provide to their traditional in-state customers would be subject to FERC regulation, rather than to the comprehensive regulatory program established by the States over LDCs' services to in-state customers.

F. The D.C. Circuit's Decision Sustaining FERC's Action

Petitioners sought review of FERC's Order 636 to the United States Court of Appeals for the District of Columbia Circuit. Citing the restrictions of NGA Sections 1(b) and 1(c), they asserted *inter alia* that FERC's attempt to exercise jurisdiction over LDCs' sales of capacity rights to in-state customers unlawfully preempted exclusive state regulation of local distribution services.

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5. Those companies are: Atlanta Gas Light Company, Chattanooga Gas Company, and Northern Indiana Public Service Company.

The Court of Appeals panel affirmed, holding that FERC possessed the authority to regulate the capacity sales by LDCs to their in-state end-users, notwithstanding the provisions of NGA Sections 1(b) and 1(c). In so affirming, the Court of Appeals gave little independent weight or credence to the important state interests involved. Its discussion of these issues is limited to only a few pages. *See* 88 F.3d at 1151-53; Pet. App. A, 76a-82a, *as amended by* Pet. App. F, 1001a-1002a.

Focusing on NGA Section 1(b), the Court of Appeals declined to view the description of state authority in that section as an *exemption*. Rather, the Court of Appeals held that the grant of authority to FERC over interstate commerce, and the grant of authority to the States over local distribution, "are a unity." 88 F.3d at 1151; Pet. App. A, 78a (a view akin to that expressed by this Court in *East Ohio Gas* that it was "surplusage"). As "a unity," there was no need to consider the scope or importance of the assigned state powers. Rather, if the regulation in question fell within the definition of FERC's authority over transportation, that would be determinative because, under Section 1(b), the States possess only the authority *not* assigned to FERC. As the Court of Appeals characterized it, "NGA § 1(b)'s reference to 'local distribution' . . . does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas." 88 F.3d at 1153; Pet. App. A, 82a.

The court acknowledged that the NGA granted the States exclusive authority to regulate local distribution companies' bundled sales of natural gas to end-users. It held, however, that unbundling changed the analysis. Because the sale of unbundled capacity rights involves transportation in interstate commerce, it is facially subject to FERC's jurisdiction under the NGA to regulate interstate pipelines, notwithstanding that the transaction is between an LDC and its in-state customer. 88 F.3d at 1153; Pet. App. A at 82a.

The Court of Appeals remitted Section 1(c), the Hinshaw exemption, to a footnote, dismissing the provision on the same theory that it applied to Section 1(b): if there was apparent federal authority over the transaction as "interstate transportation," that was sufficient to override any claim of state exemption. *See* 88 F.3d at 1153; Pet. App. A at 82a; *as amended by* Pet. App. F, 1001a-1002a. Although Section 1(c) is phrased as an exemption from federal authority, *i.e.*, it defines the persons and activities Congress intended to be regulated exclusively by the States, the Court of Appeals gave it the same kind of "unity" analysis it applied to Section 1(b). The Court of Appeals, therefore, never considered the scope of the exemption under Section 1(c), its purpose, or its importance to state regulatory schemes. The fact that the transaction that FERC sought to regulate involved a sale by an LDC, subject to state regulatory control, to an in-state customer, did not weigh in the analysis.

The LDCs moved for rehearing and rehearing *en banc*, which prompted the modification to the footnote devoted to the Hinshaw exemption. *See* Pet. App. F, 1001a-1002a. The Court of Appeals denied rehearing. *See* Pet. App. G, 1003a-1004a; Pet. App. H, 1005a-1006a.

REASONS FOR GRANTING THE WRIT

Order 636 and the Court of Appeals decision work a fundamental shift in the division of state and federal authority over the regulation of natural gas. What had heretofore been a clear grant of state authority to regulate retail gas utility services by LDCs to in-state customers has now, to a significant degree, been preempted by FERC regulation of capacity sales by LDCs to their traditional customers. Because the clear intent of Congress under NGA Sections 1(b) and 1(c), the Hinshaw exemption, is to preserve the exclusive authority of the States to regulate LDCs services to in-state end-users, FERC's regulation cannot stand.

The Court of Appeals made a fundamental analytic error. It purported to determine the scope of federal authority under Section 1(b) of the NGA without first giving full force and effect to Congress' intention to preserve the constitutional authority of the States to regulate transactions involving local distribution companies and in-state customers. After this Court applied similar reasoning in *East Ohio Gas*, Congress made clear the error of that reasoning with the enactment of Section 1(c), which reinforces the exemption from the Act afforded to areas of state regulatory authority.

Under the NGA as originally written and as reinforced by Section 1(c), federal authority extends only to those areas that are not subject to state authority. A proper analysis required the Court of Appeals to look first at the natural scope of state regulatory authority under the Act. That review would determine what was left for the federal government to regulate. By focusing instead on the apparent scope of federal (rather than state) power, and treating the States as if *they* could regulate only what was left over, the Court of Appeals inverted the analysis and reached the wrong conclusion.

I.

PRINCIPLES OF FEDERALISM AND THE NGA ITSELF REQUIRE DEFERENCE TO STATE AUTHORITY IN DETERMINING THE PROPER SCOPE OF FEDERAL AUTHORITY.

Any inquiry into preemption of state law must begin with the "basic assumption that Congress did not intend to displace state law." *Maryland v. Louisiana*, 451 U.S. 725, 746 (1981).[6]

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6. *See Commonwealth Edison Co. v. Montana*, 453 U.S. 609, 634 (1981) (" '[P]re-emption of state law by federal statute or regulation is not favored (Cont'd)

This "strong presumption against pre-emption" (*Cippollone v. Liggett Group, Inc.*, 505 U.S. 504, 523 (1992)) avoids "unintended encroachment on the authority of the States." *CSX Transp., Inc. v. Easterwood*, 113 S. Ct. 1732, 1737 (1993). The rule against preemption is strongest where the matter involves "a field which the States have traditionally occupied." *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947).

Utility regulation is "one of the most important of the functions traditionally associated with the police power of the States." *Arkansas Electric*, 461 U.S. at 377. Because it is a " 'field which the States have traditionally occupied . . . . we start with the assumption that the historic police powers of the States were not to be superseded . . . unless that was the clear and manifest purpose of Congress.' " *Pacific Gas & Elec. Co. v. State Energy Resources Conserv. & Dev. Comm'n*, 461 U.S. 190, 206 (1983) (quoting *Rice*, 331 U.S. at 230).

Congress sought to both embrace and embody this respect for the constitutional scope of state authority in the regulatory framework established by the NGA. To assume, as did the court below, that Congress intended to allow a federal agency to override state and local authority over entities historically and

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(Cont'd)
in the absence of persuasive reasons — either that the nature of the regulated subject matter permits no other conclusion, or that the Congress has unmistakably so ordained' ") (citations and internal quotations marks omitted); *CTS Corp. v. Dynamics Corp. of Am.*, 481 U.S. 69, 86 (1987) (finding no preemption based on the frustration doctrine where a state law was "consistent with the text and the purposes of" the federal law at issue); *English v. General Elec. Co.*, 496 U.S. 72, 79 (1990); *see also BFP v. Resolution Trust Corp.*, 114 S. Ct. 1757, 1764 (1994) ("Federal statutes impinging upon important state interests 'cannot . . . be construed without regard to the implications of our dual system of government' "); *id.* at 1765-66 ("where the intent to override is doubtful, our federal system demands deference to long established traditions of state regulation").

comprehensively under state control, turns the constitutional presumption on its head.

Under the NGA, Congress established a regulatory regime that would "take '*no authority* from State Commissions.' " *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. at 610 (emphasis added). Congress made state regulatory primacy a matter of *federal* law, first under Section 1(b) and then again, even more explicitly, under Section 1(c).

Under the NGA, there are thus two separate, but *not* overlapping, spheres of regulatory authority: one sphere continues the exclusive prerogative of the States over local distribution, local distribution companies and retail service to in-state customers; the other sphere, occupying roughly the area in which the Commerce Clause bars state regulation, was assigned to the federal government. *Federal Power Comm'n v. Panhandle Eastern Pipe Line Co.*, 337 U.S. at 513; *see also Federal Power Comm'n v. East Ohio Gas Co.*, 338 U.S. at 478-83 (Jackson, J., dissenting).

The state-federal regulatory framework does not contemplate a broad federal power over natural gas distribution, with the States simply given residual authority over whatever the federal agency chooses not to regulate. To the contrary, the Act was founded on (and amended to reflect) the principle that, as the first order of business, the States were to retain their authority over local distribution companies and their services to local customers. It was the federal government that was assigned the "leftovers," filling gaps (created by the dormant Commerce Clause) on the *State's* power to act. *See* 338 U.S. at 478-83.

The court below failed to heed these concerns; indeed, the Court of Appeals did not even pay them lip-service. Rather, the

court reasoned that if the subject matter of the regulation colorably fell within the scope of the grant of authority to the federal agency, there was no need to consider the scope of the authority that the statute reserves exclusively to the States. By *only* crediting the federal claim to jurisdiction and its rationale, while disdaining the need for any serious inquiry into the scope of the authority that the NGA intended to preserve for the States, the Court of Appeals performed at best only half of the required analysis.

The Court's reasoning recalls the debate between the majority and dissenters in *East Ohio Gas*. *See* discussion, *supra*, at 5-7. As the dissenters pointed out in that case, once "we pay even lip service to Congress' intention to leave to the states that which they can regulate," it is impossible to address the scope of federal power without first considering the scope and nature of the power that Congress preserved for the States. 338 U.S. at 481.

Were *East Ohio Gas* the last word on the subject, the Court of Appeals' reasoning might have been understandable as an attempt to follow this Court's direction. *East Ohio Gas* was not, however, the last word, because Congress specifically moved to reinforce the *East Ohio Gas* dissenters' position with passage of NGA Section 1(c), the Hinshaw exemption. That exemption emphasizes Congress' original intent to preserve the scope of traditional state authority and protect it from federal intrusion. The exemption also tends to demonstrate that the majority was probably not reflecting Congress' will when, in *East Ohio Gas*, it construed Section 1(b), but failed to take full account of the purpose and scope of the state authority that Congress intended to preserve.

Regardless of the scope of Section 1(b), Section 1(c) stands on its own, as an exemption from the Act. At a minimum, it is improper to determine the permissible scope of federal power

without paying heed to the reserved power of the States over local distribution companies as reflected in Section 1(c).

II.

THE COURT OF APPEALS' REASONING DOES NOT CONFORM TO THE STRUCTURE OF THE NATURAL GAS ACT.

As explained above, Congress preserved the States' authority over the local distribution companies' services to end-users within the state. That service is the core of state regulation — a subject of regulation that was to be free from federal interference or overlapping control. It is a type of regulation that typically requires comprehensive authority over the retail sales of entities subject to that authority — here, the LDCs over which the States were granted authority.

The Court of Appeals held that because the transactions in question nominally fell within the scope of FERC's grant of authority over interstate transportation, that was all that needed to be determined; the States' residual authority was merely what remains after the federal agency exercises its power.

This is a familiar form of federal court reasoning. That reasoning will often make sense in a federal system in which the federal government has the Supremacy Clause to back up its actions, leaving States to fill gaps not occupied by exercises of federal power.

It does not make sense, however, where Congress itself has acted to preserve traditional state authority, as part of federal statutory law, allowing the federal government to regulate only in an area constitutionally barred to the States. Where traditional state authority has been statutorily preserved, state power stands

on at least equal footing with federal power. Here, the scope of state authority should have been the touchstone for determining the scope of federal authority because, under the NGA, the federal government exercises only the residual power *not* preserved to the States.

Any line of reasoning under which *only* the legitimacy of the federal interest and only the scope of the apparent federal power are considered, will invariably ratify an expansive notion of federal power. This Court, however, is presumably poised to stand guard against that line of reasoning where it is not consistent with Congress' intent.[7] Because of the way that the NGA is structured, and in light of its history, the perceived federal need for uniformity must give way to the primacy of state regulation as guaranteed by the Act. This is not because of some inherent constitutional principle, but because that was precisely what Congress intended and established under the NGA.

Although we do not rely on the Tenth Amendment here, we note that the jurisprudence that has developed in connection with the Tenth Amendment serves to illustrate the error in FERC's and the Court of Appeals' reasoning.

There has, of course, been a fair amount of debate about

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7. Similar efforts by federal agencies to redefine their jurisdiction in relation to that of state agencies are pending in the communications and electric power industries. *See* First Report and Order, *Implementation of the Local Competition Provisions in the Telecommunications Act of 1996*, CC Docket No. 96-98 (Aug. 8, 1996), *stay granted*, *Iowa Utils. Board et al. v. Federal Communications Comm'n*, 1996 WL 589204 (8th Cir., Oct. 15, 1996); Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services By Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Docket Nos. RM95-8-000 and RM94-7-001 (Apr. 24, 1996), slip op. at 400-42.

whether the Tenth Amendment's reservation of powers to the States, where not assigned to the federal government, provides an enforceable limitation on the exercise of federal power. One school of thought suggests that this Amendment impliedly reserved to the States some definable powers, immune from federal regulation.

But another school of thought, drawing support from the precise wording of the Tenth Amendment, says that *all* that was reserved to the States was the power that the federal government was *not* assigned. Under this line of reasoning, all that need be determined is the scope of the assigned federal power. State authority has no independent vitality; it consists only of what remains after the broadest reach of federal authority is determined.

However apt that line of reasoning in other circumstances, it does not fit the NGA. Congress has chosen to grant primacy to the natural reach of state power and barred the federal government from invading the States' domain. In fact, the history of the Hinshaw exemption suggests that it was specifically enacted to overcome the tendency to define federal authority solely by looking at the words of the federal grant of power; the Hinshaw exemption reaffirms that the state grant of power over LDCs and their sales and distribution to retail customers must be respected, irrespective of a colorable grant of federal authority over the subject of the transaction. *See* discussion, *supra*, at 5-7. It is, therefore, impossible to understand the scope of federal authority without first addressing the intended scope of state authority, giving state authority the full play to which it is entitled under the statute as conceived. Once that is done, federal power is free to operate in the residuum *not occupied by the States*.

The Court of Appeals never did construe or consider the intended scope of state authority. Because it did not do so, it misunderstood the scope of federal authority under the Act.

III.

THE TRANSACTIONS IN QUESTION COME WITHIN THE AUTHORITY RESERVED TO THE STATES.

As pointed out above, over the last fifty years, there has been relative stability about the respective roles of state and federal authority over the natural gas industry. The States' authority over LDCs and their transactions with in-state customers has been left largely undisturbed by FERC. The time-honored understanding of the proper division of state and federal authority under the NGA has been put in play by FERC-initiated changes to the way that natural gas and natural gas services are marketed.

"Unbundling" amounts to a FERC-imposed change in what is actually being sold. It marks a shift from the sale of natural gas as delivered (with all the costs of transportation and purchase at the well-head built into the ultimate price), to the resale of LDC-contracted pipeline "capacity" to be used for the transportation of natural gas that an LDC's in-state customer can now, practically, purchase from a marketer or producer. While the statutory language cannot fit this new scheme of marketing with the same precision as it did the old, the statutory language still fits LDCs and their service to in-state end-users.

More importantly, where the language of the statute is no longer geared precisely to real world conditions — here, the real world of natural gas marketing under FERC's restructuring of the industry — the objective of a reviewing court should be to insist that the statute be administered consistent with the basic structure and purpose of the plan as originally conceived. Here, FERC ought not be able to use the basic shifts in market that it has itself created in order to bootstrap itself into a position of authority over transactions at the core of the States' authority.

Maintenance of a cohesive state regulatory regime over LDCs and their relations with in-state customers is central to the preservation of state regulatory authority.

The Hinshaw exemption mandates that the provisions of the NGA shall not apply to persons (a) engaged in either the interstate transportation of gas or the sale for resale of gas; (b) receiving gas at or within the boundary of a State, where "all the natural gas so received is ultimately consumed within such State"; and (c) whose rates, services and facilities are "subject to regulation by a State commission." *See* NGA § 1(c), 15 U.S.C. § 717(c). LDCs are such "persons." Section 1(c) also provides that a certification is "conclusive evidence" of the States' regulatory jurisdiction. The plain language of NGA Section 1(c) says that "the provisions of the NGA shall not apply to any persons" that come within its terms. Thus, LDCs are *not* persons that FERC can subject to the provisions of the NGA.

FERC has never contested that most LDCs come within the terms of NGA Section 1(c). The Court of Appeals, however, never even addressed the issue because it mistakenly believed that if the regulation fell within FERC's apparent grant of regulatory authority over interstate commerce, that was sufficient to override state authority.

Even if the language of NGA Sections 1(b) and 1(c) no longer provide a perfect fit with the restructured market, the division of power under the new regime must parallel the basic structure of regulation embedded in the Natural Gas Act. The basic structure of the Act contemplates that the States would regulate transactions between LDCs and their in-state end-users as part of a comprehensive scheme of intrastate regulation. The objective was to leave regulation of LDCs entirely in the hands of the States. The nature of state regulation of LDCs in order to serve in-state customers requires comprehensive control over all such transactions.

The court below held, in effect, that the transaction between the LDC and the local customer could be subjected to federal control because the "unbundled" service that was the subject of the intrastate transaction had an interstate nexus. It offered no explanation why — in terms of the purposes of NGA, the purpose of the exemptions, and the nature of the historic power of the States which Congress sought to preserve — unbundling should remove such transactions from exclusive state authority. Rather, the Court of Appeals focused only on the federal grant of power, FERC's objectives and FERC's reasons for subjecting such transactions to federal control.

There can be little suggestion today that the States cannot regulate a contract between a local distribution company and its in-state customer, involving gas to be consumed within the State. The fact that the subject matter of the contract involves, in part, interstate transportation of gas would not place the contract between LDC and the in-state customer beyond the States' authority.

To be sure, the issue presented here revives, in some measure, the debate between the majority and the dissenters in *East Ohio Gas*. That was a debate over whether the States' powers, preserved by Section 1(b), should be construed consistent with (what is now) 60-year-old case law under the dormant Commerce Clause, or measured by more modern constitutional standards to reflect Congress' respect of state authority. *See* discussion, *supra*, at 5-7. In Petitioners' view, Congress' original intention to preserve the primary role of the States supported the dissenters in *East Ohio Gas*. But the issue presented in the instant case would *not* simply be a rehash of old problems: to the contrary, enactment of Section 1(c) necessarily changed the statutory framework and requires the Court to renew its attention to this area.

The form of state regulation that Congress sought to preserve contemplates a *comprehensive* scheme of rate control over LDCs. Such regulatory regimes require consistency and exclusivity of control over LDCs' relationship with their local customers, whether the transaction in question involves a sale of "bundled" natural gas for use within the State, or unbundled segments of a total package of services that results in the delivery of natural gas for use within the State (and which the in-state customer is purchasing in lieu of a purchase of "bundled" natural gas.) The comprehensive structure of the state programs are thus defeated by subjecting LDC capacity sales to federal control.

Whereas FERC clearly favors a nationwide, uniform approach to sales and resales of capacity, the fundamental premise of the grant of authority to the States was that there would be, or could be, variation between States reflecting the use of the state regulatory program to serve local objectives.

IV.

FERC'S PREEMPTIVE RULING FUNDAMENTALLY DISRUPTS STATE REGULATION OF NATURAL GAS UTILITIES.

As should be clear, this petition presents no challenge to the concept of "unbundling" or the overall objectives of the federal plan. Rather, it concerns only the question of ultimate control over one aspect of the current market structure, the resale of capacity by LDCs to in-state customers. That part of the market is a small part of the federal program, but is a core component of the state regulatory framework. That framework will be disrupted by FERC's assertion of authority over these LDC transactions.

Congress clearly intended that state policies, and the objectives of the state regulatory scheme, prevail in this area of historic state authority over LDCs and intrastate customers.

A. The Problem Created By Piecemeal Regulation Of LDC Service

For state regulators, LDC capacity release service to local customers is simply one element of a larger program whereby LDC services to gas consumers are unbundled. These unbundled services stand in lieu of earlier sales of "bundled" gas to those same customers.

Generally speaking, state regulatory agencies share the perception that the LDC unbundling process is an important, strategic step in the direction of achieving the goal of consumer economic protection in a more competitive energy marketplace. But those agencies also understand that LDC capacity release is a means by which the gas consumer that has acquired its own gas supplier can be certain that this gas will be transported through the existing interstate gas transportation facilities for delivery to its local gas utility's system. In other words, more and more gas consumers are now *not* purchasing gas from the LDC. But the gas consumer still finds it convenient to obtain the transportation necessary to bring the gas to it — through distribution lines outside the state and inside the state — from the LDC, just as always.

For its part, FERC sees LDCs' resales or assignments of capacity to in-state customers as simply one part of its nationwide market structure. LDCs' transactions with in-state customers are not — so far as FERC is concerned — entitled to any special consideration. FERC thus views LDC capacity release to in-state customers as influencing or determining which customers will have how much access to the LDC's interstate

pipeline supplier's capacity and at what price; thus, the LDC is seen as allocating interstate pipeline capacity, just as interstate pipelines do. FERC seeks to maintain exclusive control over the selection of pipeline capacity users and to assert control over LDC's capacity assignment transactions, even where such transactions involve an LDC's effort to serve its traditional local customer.

B. State And Federal Objectives Conflict

The basic objective of federal regulation of LDC capacity release transactions is to make interstate capacity available to the highest bidder, wherever located. This objective is achieved by the mandate that any release proposed at less than the ceiling rate be subject to an auction process so that any party, whether or not located within the LDC's service area, can acquire an LDC's capacity by offering the highest bid for it. Thus, for the FERC, an LDC's resale to its traditional in-state customers of the capacity rights that it has previously purchased is just one more sale of transportation, no different from any other. FERC seeks to subject all such sales to its authority.

State regulatory objectives focus on service to local customers and the melding of the opportunities created by "unbundling" with the comprehensive regulatory system focusing on *state* energy policy. In most cases, state goals include consumer economic protection and reliability of service. These goals are not inconsistent with unbundling, but they require that the States be able to address the provision of unbundled service as part of the overall regulation of LDCs. Thus, state regulation of LDC capacity release may be an important component of a *state* unbundling program designed to provide state gas consumers with both the economic benefits of a more competitive natural gas marketplace *and* reliable gas utility service.

For example, in some States, the unbundling program includes an LDC capacity release involving *blended* capacity releases. In such a plan, the gas transportation occurring upstream of the LDC's intrastate facilities is deemed to be provided in part by each of the LDC's pipeline suppliers rather than exclusively by any particular pipeline company. The blending approach avoids the arbitrary allocation of the more expensive pipeline transportation service to any specific customer or customers, and likewise, the allocation or assignment of the least costly pipeline capacity to specific consumers. Such a plan is designed to broadly provide the benefits of unbundling to all state customers, without creating great disparities among in-state customers on price and service. However, such a blended approach is simply not compatible with Order 636, which requires that a particular increment of an LDC's capacity rights on a particular pipeline be released to the highest bidder.

The pipeline capacity that LDCs now have available for capacity sale has been acquired by LDCs to service their customers and has typically been reviewed by state regulators with these ends in mind. Thus, the rates that have been set have allowed those purchases for the benefit of in-state customers, as part of the state regulatory program. At bottom, however, it is the objective of the federal program to allow capacity sales to the highest bidder, wherever located. The result is that in-state customers may never be allowed to benefit from the investment they made in LDC capacity.

C. Customer Choice Initiatives

In light of the restructured market promoted by FERC, a growing number of the LDCs filing this Petition are now offering to more of their customers the opportunity to choose among gas

sellers.[8] This trend is expected ultimately to reach most U.S. residential gas consumers.

As these customer choice programs are implemented in the various states, gas consumers selecting new retail gas sellers confront the need for transportation service from their LDC. As they do so, they can be expected to make use of the gas transportation facilities already in place, including interstate pipeline facilities made available through some form of capacity release transaction with their LDC. The access of these consumers to their newly acquired gas supply source on an *economical and reliable* basis may well depend on whether their LDC is subject to a comprehensive, coherent state regulatory program or whether, instead, it is subject to both state and federal regulatory authority designed to achieve different and sometimes conflicting objectives. Thus, protection of consumers, including economical access to "unbundled" gas, may very well turn on the efficacy of state regulatory control, rather than piecemeal federal control of capacity release by LDCs to in-state customers.

* * *

The court below emphasized that FERC perceived the extension of its authority to LDC capacity resales to be part of a national program, serving federal reform efforts in the natural gas industry. As shown above, however, Congress intended to afford state regulators primacy with respect to the relationship between LDCs' and their in-state customers. Those intrastate contracts and relationships, involving the delivery of natural gas within the state, are subject to state control, notwithstanding that their subject matter involves the movement of gas in

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8. In most states where customer choice of gas seller has been widely offered, that opportunity has first been provided on an experimental basis through a "pilot program." *See* report cited at note 3, *supra*.

interstate commerce. Under the NGA as written, the federal program of control over the natural gas industry must acknowledge its statutory limits and accommodate state control over that relationship.

CONCLUSION

The Petition for Writ of Certiorari should be granted.

Respectfully submitted,

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Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,

Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

AND RELATED PETITIONS

Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

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APPENDIX A — OPINION — *UNITED DISTRIBUTION COMPANIES v. FEDERAL ENERGY REGULATORY COMMISSION*, 88 F.3d 1105 (D.C. Cir. 1996)

UNITED DISTRIBUTION COMPANIES, Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION, Respondent.

Windward Energy & Marketing Company, et al., Intervenors.

Nos. 92-1485, 92-1495, 92-1496, 94-1171, 94-1173 to 94-1181, 94-1183 to 94-1185, 94-1187 to 94-1190, 94-1193, 94-1194, 94-1196 to 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231 to 94-1234, 94-1236 to 94-1243, 94-1246 to 94-1249, 94-1252, 94-1256 to 94-1259, 94-1263 to 94-1265, 94-1267 and 94-1270.

United States Court of Appeals,
District of Columbia Circuit.

Argued Feb. 21, 1996.

Decided July 16, 1996.

As Amended Oct. 29, 1996.

88 F.3d 1105 (D.C. Cir. 1996)

* * *

Appendix A

On Petitions for Review of Orders of the Federal Energy Regulatory Commission.

Frederick Moring, Washington, DC, Roy R. Robertson, Jr., Chicago, IL, Michael W. Hall, O. Julia Weller, Washington, DC, Roberta L. Halladay, Washington, DC, Daniel F. Collins, Washington, DC, Robert T. Hall, III, New York City, Harvey L. Reiter, Washington, DC, Lee A. Alexander, Washington, DC, Edward J. Grenier, Jr., Washington, DC, Charles F. Wheatley, Jr., John P. Gregg, John T. Miller, David W. D'Alessandro, Washington, DC, Denise C. Goulet, Harrisburg, PA, and Philip M. Marston, Alexandria, VA, argued the causes for petitioners, with whom Dana C. Contratto, John E. Holtzinger, Jr., Kevin M. Downey, Kenneth T. Maloney, William I. Harkaway, Donald K. Dankner, Frederick J. Killion, Jeffrey L. Futter, Stephen L. Huntoon, Douglas M. Canter, Mary E. Baluss, Kristine L. Delkus, Christopher J. Barr, John K. Keane, Jr., Telemac N. Chryssikos, James K. Mitchell, Paul K. Sandness, Kevin J. Lipson, Scott Silverstein, Janice A. Alperin, Christine R. Pembroke, Kenneth M. Simon, Mitchell F. Hertz, Randolph Q. McManus, William L. Slover, Donald G. Avery, Andrew B. Kolesar, III, Laurence E. Skinner, William I. Harkaway, Michael W. Hall, William H. Penniman, Glen S. Howard, Sterling H. Smith, Gail S. Gilman, Thomas E. Hirsch, III, David K. Schumacher, Frederic G. Berner, Jr., Nancy Y. Gorman, Debra L. Raggio Bolton, Susan N. Kelly, William T. Miller, Elisabeth R. Myers-Kerbal, Glenn W. Letham, Steven M. Sherman, Don C. Uthus, Timothy P. Ingram, Richard A. Rapp, Jr., Jennifer N. Waters, Kelly A. Daly, Edward W. O'Neill, Harvey Y. Morris, Theresa V. Czarski, Paula M. Carmody, Diane Munns, Lawrence F. Barth, Veronica A. Smith, John F. Povilaitis, Harold L. Stoller, Jr., Penny G. Baker, Helene S. Wallenstein, Thomas B. Nicholson, Charles D. Gray, Robert S. Tongren, Margaret Ann

Samuels, Jospeh P. Serio, Yvonne Ranft, Deborah Y. VanDervort, Robert J. Mussallem, Darrell S. Townsley, Ellen M. Averett, Richard A. Solomon, Robert K. Johnson, William H. Smith, Jr. and Kim M. Clark were on the briefs. Jack M. Wilhelm, Robin M. Nuschler, Douglas J. Law, Kathleen L. Mazure, Phillip G. Lookadoo, Toni M. Fine, John T. Stough, Jr., Robert I. White, Jacolyn A. Simmons, Kent D. Murphy, Marc Richter, Richard A. Rapp, Jr., Don S. Smith, Steven A. Weiler, Paul W. Fox, Kevin J. McIntyre, Scott S. Ives, Donald C. Shepler, Jr., James Howard, Robert S. Hall, Jr., James F. Bowe, Jr., Steven H. Lasher, Donald G. Avery, David C. Dickey, Robert F. Shapiro, Jack M. Irion, Philip B. Malter, Harold L. Talisman, Jeanne M. Bennett and Robert H. Benna entered appearances.

Jerome M. Feit, Solicitor, Federal Energy Regulatory Commission, Washington, DC, Joseph S. Davies, Deputy Solicitor, Bethesda, MD, and Susan J. Court, Special Counsel, Washington, DC, argued the causes for respondent, with whom Timm L. Abendroth, Eric L. Christensen, Randolph L. Elliott, Edward S. Geldermann and Janet K. Jones, Attorneys, were on the brief. Thomas J. Lane and Jill Hall, Attorneys, entered appearances. Henry S. May, Jr., Houston, TX, argued the cause for intervenors, with whom Judy M. Johnson, Clifton S. Rankin, Richard J. Kruse, Jeffrey D. Komarow, James W. McTarnaghan, Allan W. Anderson, Jr., David K. Schumacher, Frederick T. Kolb, Daniel F. Collins, Janice A. Alperin, Christine R. Pembroke, Michael W. Hall, Michael J. Manning, Kenneth R. Carretta, James P. White, William T. Miller, John P. Gregg, Elisabeth R. Myers-Kerbal, Emery J. Biro, III, Norma J. Rosner, David G. Stevenson, Bruce A. Connell, MaryJane Reynolds, Leslie J. Lawner, Jane E. Wilson, Joseph R. Hartsoe, R. Brent Harshman, Richard C. Green, Douglas W. Rasch, John H. Cheatham, III, Bud J. Becker, O. Julia Weller, Paul F. O'Konski, Marge

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Appearances were also filed by Carl M. Fink, Howard E. Shapiro, James C. Moffatt, Jennifer B. Corwin, Robert A. Nuernberg, Ronald D. Eastman, Oleta J. Harden, Barbara K. Heffernan, Cheryl L. Jones, Tom Rattray, Gearold L. Knowles, Margaret Ann Samuels, David C. Dickey, Thomas E. Hirsch, III, Britton White, Jr., James D. Senger, James J. Flood, Joel F. Zipp, Leja D. Courter, Ronald E. Christian, James C. Moffatt, Shippen Howe, John R. Staffier, Robert A. Nelson, Timothy C. Bladek, Andrew N. Greene, Edward B. Myers, Carolyn Y. Thompson, Kenneth D. Brown, Frank R. Lindh, Keith T. Sampson, Raymond N. Shibley, Cheryl J. Walker, Thomas J. Eastment, Michael L. Pate, Barbara S. Jost, Michael E. Small,

Appendix A

Robin M. Nuschler, John C. Walley, Gary E. Guy, Stephen J. Small, Susan D. McAndrew, Timothy N. Black, David W. Anderson, David L. Huard, David J. Evans, George H. Rothschild, Jr., Charles H. Shoneman, Randall S. Rich, Joel L. Greene, Joseph M. Oliver, Jr., M. Lisanne Crowley, Mark C. Darrell, John B. Chapman, John K. McDonald, Richard E. Powers, Jr., Sylvia P. McCormack, Jeffrey M. Petrash, Phillip G. Lookadoo, J. Neises, S.D. Holbrook, James D. McKinney, Jr., John J. Wallbillich, Joshua L. Menter, Jack P. Grimaldi, J.D. Steelman, Jr., Nicholas W. Fels, Anthony J. Ivancovich, Rebecca S. Haney, John S. Grube, Stuart W. Conrad, Robert B. Langstaff, Michael J. Gianunzio, David W. Rubadue, Marilyn A. Specht, Paul W. Fox, Bruce F. Kiely, Mark K. Lewis, Jack M. Wilhelm, Michael R. Waller, Mark C. Moench, Paul M. Flynn, Frederick J. Killion, Michael Thompson, Wade H. Hargrove, Jr., Donald W. McCoy, Bruce Henderson, Kris L. Terry, Joseph M. Marcoux, Elizabeth A. Ward, Philip F. Cronin, Jr., Stephen L. Huntoon, Nancy J. Skancke, Timothy A. Beverick, Kenton L. Erwin, Scott P. Klurfeld, David B. Robinson, Anita T. Gallucci, Michael P. May, Daniel J. Guttman, Jr., William Bingham, James H. Holt, Don P. Garber, Floyd L. Norton, IV, Dennis D. Ahlers, David I. Bloom, Thomas M. Patrick, John M. Hopper, Jr., Mary A. Walker, Joseph E. Mixon, Nancy J. Skancke, Cecil W. Talley and Arthur L. Smith.

Before: WALD, SENTELLE and ROGERS, Circuit Judges.

Opinion for the Court filed PER CURIAM.*

* * *

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* Parts III and V.A-B, E.3-4 and F are by Judge Wald; Parts IV and V.C-D and E.1-2 are by Judge Sentelle; and Parts I and II are by Judge Rogers.

Appendix A

PER CURIAM:

I. Introduction

In Order No. 636,[1] the Federal Energy Regulatory Commission ("Commission" or "FERC") took the latest step in its decade-long restructuring of the natural gas industry, in which the Commission has gradually withdrawn from direct regulation of certain industry sectors in favor of a policy of "light-handed regulation" when market forces make that possible. We review briefly the regulatory background for natural gas.

A. *Background: Natural Gas Industry Structure*

The natural gas industry is functionally separated into production, transportation, and distribution. Traditionally, before the move to open-access transportation, a producer extracted the gas and sold it at the wellhead to a pipeline company. The pipeline company then transported the gas through high-pressure pipelines and re-sold it to a local distribution company (LDC). The LDC in turn distributed the gas through its local mains to residential and industrial users. *See generally* EDWARD C. GALLICK, COMPETITION IN THE NATURAL GAS INDUSTRY 9-12 (1993).

The Natural Gas Act (NGA), ch. 556, 52 Stat. 821 (1938)

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1. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939, order on reh'g, Order No. 636-A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950, *order on reh'g*, Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *reh'g denied*, 62 F.E.R.C. ¶ 61,007 (1993).

(codified as amended at 15 U.S.C. §§ 717-717w (1994)), enacted in 1938, gave the Commission jurisdiction over sales for resale in interstate commerce and over the interstate transportation of gas, but left the regulation of local distribution to the states.[2] NGA § 1(b), 15 U.S.C. § 717(b). The NGA was intended to fill the regulatory gap left by a series of Supreme Court decisions that interpreted the dormant Commerce Clause to preclude state regulation of interstate transportation and of wholesale gas sales. *See Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377- 80, 103 S.Ct. 1905, 1908-10, 76 L.Ed.2d 1 (1983). The overriding purpose of the NGA is " 'to protect consumers against exploitation at the hands of natural gas companies.' " *FPC v. Louisiana Power & Light Co.*, 406 U.S. 621, 631, 92 S.Ct. 1827, 1833, 32 L.Ed.2d 369 (1972) (quoting *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 610, 64 S.Ct. 281, 291, 88 L.Ed. 333 (1944)). Federal regulation of the natural gas industry is thus designed to curb pipelines' potential monopoly power over gas transportation.[3] The enormous economies of scale involved in the construction of natural gas pipelines tend to make the transportation of gas a natural monopoly.[4] Indeed, even with

2. In 1954, Congress added the "Hinshaw exemption," which excludes from the Commission's jurisdiction gas that is received within a state (or at the state boundary) and is consumed within that state, provided that the gas is subject to state regulation. NGA § 1(c), 15 U.S.C. § 717(c).

3. The seminal analysis of pipelines' market power over transportation can be found in the Federal Trade Commission (FTC) report that led to the enactment of the NGA. *See* SEN. DOC. NO. 92, pt. 84A, 70th Cong., 1st Sess. (1935).

4. A natural monopoly occurs when, because of the high ratio of fixed costs to variable costs, a single firm has declining average costs at the level of demand in the industry, such that the single firm can supply the service more cheaply than two firms could. RICHARD A. POSNER, ECONOMIC ANALYSIS OF LAW § 12.1, at 343-45 (4th ed.1992).

the expansion of the national pipeline grid, or network, in recent decades, many "captive" customers[5] remain served by a single pipeline.[6] Order No. 436, ¶ 30,665, at 31,473.[7]

Even though the market function potentially subject to monopoly power is the transportation of gas, for many years the Commission also regulated the price and terms of sales by producers to interstate pipelines. *See Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 677-84, 74 S.Ct. 794, 796-800, 98 L.Ed. 1035 (1954). Producer price regulation was widely regarded as a failure, introducing severe distortions into what otherwise would have been a well-functioning producer sales

5. We use the term "captive customer" to refer to customers "who must use gas and can only obtain it from one provider." *Mississippi Valley Gas Co. v. FERC*, 68 F.3d 503, 506 (D.C.Cir.1995); *see also Wisconsin Gas Co. v. FERC*, 770 F.2d 1144, 1150, 1160 (D.C.Cir.1985) ("[F]ull requirements [or 'captive'] customers purchase their entire natural gas supply from one pipeline and, because of their geographical location, are unable to swing off the system to obtain cheaper supplies of gas.").

6. As of 1985, 10% of gas deliveries were to LDCs served by four or more pipelines, 39.5% to LDCs served by three pipelines, 28% to LDCs served by two pipelines, and 22.5% to LDCs served by a single pipeline. STEPHEN F. WILLIAMS, THE NATURAL GAS REVOLUTION OF 1985, at 4 (1985).

7. Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,665, order on reh'g, Order No. 436-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,688, order on reh'g, Order No. 436-C, 34 F.E.R.C. ¶ 61,404, *order on reh'g*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405, *order on reh'g*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986), *vacated and remanded sub nom. Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C.Cir.1987) (AGD I), *cert. denied*, 485 U.S. 1006, 108 S.Ct. 1468, 1469, 99 L.Ed.2d 698 (1988).

market. *See* STEPHEN G. BREYER & PAUL W. MACAVOY, ENERGY REGULATION BY THE FEDERAL POWER COMMISSION 56-88 (1974). When a severe gas shortage developed in the 1970s, Congress enacted the Natural Gas Policy Act of 1978 (NGPA), Pub.L. No. 95-621, 92 Stat. 3351 (codified as amended at 15 U.S.C. §§ 3301-3432 (1994)), which gradually phased out producer price regulation. Under the NGPA's partially regulated producer-price system, many pipelines entered into long-term contractual obligations, in what were known as "take-or-pay" provisions, to purchase minimum quantities of gas from producers at costs that proved to be well above current market prices of gas. *See* Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 ENERGY L.J. 1, 11-16 (1988).

The problem of pipelines' take-or-pay settlement costs has plagued the industry and the Commission over the last fifteen years. The Commission's initial response to escalating pipeline take-or-pay liabilities was to authorize pipelines to offer less expensive sales of third-party (non-pipeline-owned) gas to non-captive customers while still offering only higher-priced pipeline gas to captive customers.[8] The court struck down these measures

8. First, the Commission approved special marketing programs, under which pipelines agreed to transport third-party gas to industrial end-users in exchange for the producer's agreement to credit the transported gas to the pipeline's take-or-pay liability. *See Columbia Gas Transmission Corp.*, 25 F.E.R.C. ¶ 61,220, *order on reh'g*, 25 F.E.R.C. ¶ 61,401 (1983), *order on reh'g*, 26 F.E.R.C. ¶ 61,031 (1984). Second, the Commission authorized selective transportation programs, under which a pipeline received a blanket certificate to transport third-party gas and was allowed to offer this service to its customers on a selective basis. *See* Order No. 234-B, *Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors*, [Regs. Preambles 1982-85] F.E.R.C.

(Cont'd)

because the Commission "ha[d] not adequately attended to the agency's prime constituency," captive customers vulnerable to pipelines' market power. *Maryland People's Counsel v. FERC*, 761 F.2d 780, 781 (D.C.Cir.1985) (MPC II); *see also Maryland People's Coun*sel v. FERC, 761 F.2d 768, 776 (D.C.Cir.1985) (MPC I). In response to the court's decisions in MPC I and MPC II, the Commission embarked on its landmark Order No. 436 rulemaking. See Order No. 436, ¶ 30,665, at 31,467.

B. *Order No. 436: Open-Access Transportation*

In Order No. 436, the Commission began the transition toward removing pipelines from the gas-sales business and confining them to a more limited role as gas transporters. Under a new Part 284 of its regulations,[9] the Commission conditioned receipt of a blanket certificate for firm transportation of third-party gas on the pipeline's acceptance of non-discrimination requirements guaranteeing equal access for all customers to the

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Stats. & Regs. (CCH) ¶ 30,476 (1983); Order No. 319, *Sales and Transportation by Interstate Pipelines and Distributors*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,477, *order on reh'g*, Order No. 319-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,512 (1983).

9. Customers who receive service under a blanket certificate as authorized in Order No. 436 are known as Part 284 customers. Customers who receive individually certificated service, to which the open-access conditions do not apply, are known as Part 157 customers, or § 7(c) customers. Although the Commission's current policy is no longer to issue Part 157 certificates, *Blue Lake Gas Storage Co.*, 59 F.E.R.C. ¶ 61,118, *reh'g denied*, 61 F.E.R.C. ¶ 61,284 (1992), existing Part 157 certificates remain in effect.

new service.[10] Order No. 436, ¶ 30,665, at 31,497-518. In effect, the Commission for the first time imposed the duties of common carriers upon interstate pipelines. *See Associated Gas Distributors v. FERC*, 824 F.2d 981, 997 (D.C.Cir.1987) (*AGD I*), *cert. denied*, 485 U.S. 1006, 108 S.Ct. 1468, 1469, 99 L.Ed.2d 698 (1988). By recognizing that anti-competitive conditions in the industry arose from pipeline control over access to transportation capacity, the equal-access requirements of Order No. 436 regulated the natural-monopoly conditions directly. In addition, every open-access pipeline was required to allow its existing bundled firm-sales customers to convert to firm-transportation service and, at the customer's option, to reduce its firm-transportation entitlement (its "contract demand"). Order No. 436, ¶ 30,665, at 31,518-33. Moreover, the Commission established a flexible rate structure under which transportation charges were limited to the maximum approved rate (based on fully allocated costs) but pipelines could selectively discount down to the minimum approved rate (based on average variable cost). *Id.* at 31,533-49.

The court largely approved Order No. 436, but the principal stumbling-block was the unresolved problem of uneconomical pipeline-producer contracts in the transition to the unbundled environment. The Commission had decided not to provide pipelines with relief from their take-or-pay liabilities, even though the introduction of open-access transportation in Order No. 436 would likely exacerbate the problem by reducing pipeline sales.[11] *AGD I*, 824 F.2d at 1021-23. After the court

10. Pipelines generally offer two forms of transportation service: firm transportation, for which delivery is guaranteed, and interruptible transportation, for which delivery can be delayed if all the capacity on the pipeline is in use.

11. The Commission limited itself to re-affirming a previous policy (Cont'd)

remanded the case on the ground that the Commission's inaction on take-or-pay did not exhibit reasoned decision making in light of open access, *id.* at 1030, the Commission adopted various interim measures in Order No. 500.[12] First, it instituted a "crediting mechanism," under which a pipeline could apply any third-party gas that it transported toward the pipeline's minimum-purchase obligation from that particular producer. Order No. 500, ¶ 30,761, at 30,779-84. Second, the Commission adopted two alternative cost-recovery mechanisms. As customary, a pipeline could recover all of its prudently incurred costs in its commodity (sales) charges, although that could prove difficult for pipelines with shrinking sales-customer bases. In the alternative, under the equitable- sharing approach, a pipeline offering open-access transportation could, if it voluntarily absorbed between twenty-five and fifty percent of the costs, recover an equal share of the costs through a "fixed charge" and recover the remaining amount (up to fifty percent) through a volumetric surcharge based on total throughput (and thus borne

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statement on take-or-pay liabilities that deferred the issue to individual rate-case filings. Order No. 436, ¶ 30,665, at 31,560-69; *see Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,637 (1985); 18 C.F.R. § 2.76.

12. Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,761, *order on reh'g*, Order No. 500-A, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH)P 30,770, *order on reh'g*, Order No. 500-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,772, *order on reh'g*, Order No. 500-C, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,786 (1987), *order on reh'g*, Order No. 500-D, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,800, *order on reh'g*, Order No. 500-E, 43 F.E.R.C. ¶ 61,234, *order on reh'g*, Order No. 500-F,

(Cont'd)

by both sales and transportation customers alike).[13] *Id.* at 30,784-92; 18 C.F.R. § 2.104. Third, the Commission authorized pipelines not recovering take-or-pay costs in any other manner to impose a "gas inventory charge" (GIC), a fixed charge for "standing ready" to deliver gas — the sales analogue to a reservation charge. Order No. 500, ¶ 30,761, at 30,792-94; 18 C.F.R. § 2.105.

The Commission's alternative solutions to the problem of take-or-pay settlement costs in Order No. 500 fared poorly on judicial review. First, the court remanded the crediting mechanism for an explanation of whether the Commission had the requisite authority under § 7 of the NGA. *American Gas Ass'n v. FERC*, 888 F.2d 136, 148-49 (D.C.Cir.1989) (AGA I). After the Commission explained its § 7 authority for the crediting mechanism in Order No. 500-H,[14] the court upheld the crediting mechanism.[15] *American Gas Ass'n v. FERC*, 912 F.2d 1496,

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[Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,841 (1988), *order on reh'g*, Order No. 500-G, 46 F.E.R.C. ¶ 61,148, *vacated and remanded sub nom. American Gas Ass'n v. FERC*, 888 F.2d 136 (D.C.Cir.1989) (*AGA I*).

13. The remaining costs "may be recovered either through a commodity rate surcharge or a volumetric surcharge on total throughput." 18 C.F.R. § 2.104(a). In *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1299- 1300 (D.C.Cir.1992), the court upheld the Commission's reading of its regulation that a commodity rate surcharge must also be based on total throughput.

14. Order No. 500-H, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,867 (1989), *order on reh'g*, Order No. 500-I, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. ¶ 30,880, *remanded sub nom. American Gas Ass'n v. FERC*, 912 F.2d 1496 (D.C.Cir.1990) (*AGA II*).

15. The Commission terminated the crediting mechanism as of
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1509-13 (D.C.Cir.1990) (AGA II). Second, the court struck down the equitable-sharing cost-recovery mechanism on the ground that the Commission's "purchase deficiency" method for calculating the "fixed charge," which assigned costs to each customer based on how much its purchases had declined over the relevant preceding period, violated the filed-rate doctrine. *Associated Gas Distributors v. FERC*, 893 F.2d 349, 354-57 (D.C.Cir.1989) (*AGD II*), *reh'g en banc denied*, 898 F.2d 809 (D.C.Cir.), *cert. denied*, 498 U.S. 907, 111 S.Ct. 277, 278, 112 L.Ed.2d 233 (1990). The Commission responded to the invalidation of the "purchase deficiency" method in *AGD II* by adopting Order No. 528,[16] which allowed pipelines, in the "fixed charge," to pass through a portion of costs to customers based on any of several measures of current (rather than past) demand or usage, with the intent of avoiding the filed-rate problem. Order No. 528, ¶ 61,163, at 61,597-98. Finally, the court struck down the Commission's approval of a GIC on a particular pipeline because it had given undue weight to the pipeline's customers' having agreed to the GIC and failed adequately to consider the interests of end-users. *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1003-05 (D.C.Cir.1990).

Congress completed the process of deregulating the producer sales market by enacting the Natural Gas Wellhead Decontrol Act of 1989, Pub.L. No. 101-60, 103 Stat. 157

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December 31, 1990. Order No. 500-K, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,917, *reh'g denied*, Order No. 500-L, 55 F.E.R.C. ¶ 61,489 (1991).

16. Order No. 528, *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 53 F.E.R.C. ¶ 61,163 1990 WL 488926 (1990), *order on reh'g*, Order No. 528-A, 54 F.E.R.C. ¶ 61,095, *reh'g denied*, Order No. 528-B, 55 F.E.R.C. ¶ 61,372 (1991).

(codified in scattered sections of 15 U.S.C.). As the House Committee on Energy and Commerce emphasized, the Commission's creation of open-access transportation was "essential" to Congress' decision completely to deregulate wellhead sales. H.R.REP. NO. 29, 101st Cong., 1st Sess. 6 (1989), U.S.Code Cong. & Admin.News 1989, pp. 51, 56. The committee report declared also that "[b]oth the FERC and the courts are strongly urged to retain and improve this competitive structure in order to maximize the benefits of decontrol."[17] *Id.* The committee expected that, by ensuring that "[a]ll buyers [are] free to reach the lowest-selling producer," *id.*, open-access transportation would allow the more efficient producers to emerge, leading to lower prices for consumers, *id.* at 3, 7.

C. *Order No. 636: Mandatory Unbundling*

In Order No. 636, the Commission declared the open-access requirements of Order No. 436 a partial success. The Commission found that pipeline firm sales, which in 1984 had been over 90 percent of deliveries to market, had declined by 1990 to 21 percent. Order No. 636, ¶ 30,939, at 30,399 tbl. 1. On the other hand, only 28 percent of deliveries to market in 1990 were firm transportation, whereas 51 percent of deliveries used interruptible transportation. *Id.* at 30,399 & n. 61. The Commission concluded that many customers had not taken advantage of Order No. 436's option to convert from firm-sales to firm-transportation service because the firm-transportation component of bundled firm-sales service was "superior in

17. The committee added that "[t]his legislation does not deregulate gas pipelines, and the Committee will continue its oversight of the FERC to ensure that captive residential consumers are not disadvantaged, and that the current competitive 'open access' pipeline system is maintained." H.R.REP. NO. 29, *supra*, at 4, U.S.CODE CONG. & ADMIN.NEWS 1989, P. 53.

quality" to stand-alone firm-transportation service. *Id.* at 30,402. In particular, the Commission found that stand-alone firm-transportation service was often subject to daily scheduling and balancing requirements, as well as to penalties for variances from projected purchases in excess of ten percent. Moreover, pipelines usually did not offer storage capacity on a contractual basis to stand-alone firm-transportation shippers. *Id.* The result was that many of the non-converted customers used the pipelines' firm-sales service during times of peak demand but in non-peak periods bought third-party gas and transported it with interruptible transportation. The Commission found that "[i]t is often cheaper for pipeline sales customers to buy gas on the spot market, and pay the pipeline's demand charge plus the interruptible rate, than to purchase the pipeline's gas." *Id.* at 30,400. Because of the distortions in the sales market, these customers often paid twice for transportation services and still received an inferior form of transportation (interruptible rather than firm). *Id.* Because of the anti-competitive effect on the industry, the Commission found that pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA. *Id.* at 30,405.

The Commission's remedy for these anti-competitive conditions, and the principal innovation of Order No. 636, was mandatory unbundling of pipelines' sales and transportation services. By making the separation of the two functions mandatory, the Commission expects that pipelines' monopoly power over transportation will no longer distort the sales market. Order No. 636, ¶ 30,939, at 30,406-13; Order No. 636-A, ¶ 30,950, at 30,527-46; Order No. 636- B, ¶ 61,272, at 61,988-92. To replace the firm-transportation component of bundled firm-sales service, the Commission introduced the concept of "no-notice firm transportation," stand-alone firm transportation without penalties. Those customers who receive bundled firm-

sales service have the right, during the restructuring process, to switch to no-notice firm-transportation service. Pipelines that did not offer bundled firm-sales service are not required to offer no-notice transportation; but if they do, they must offer no-notice transportation on a non-discriminatory basis. Order No. 636, ¶ 30,939, at 30,421-25; Order No. 636-A, ¶ 30,950, at 30,570-77; Order No. 636-B, ¶ 61,272, at 62,006-10; *see* 18 C.F.R. § 284.8(a)(4).

In contrast to the continued regulation of the transportation market, the Commission essentially deregulated the pipeline sales market. The Commission issued every Part 284 pipeline a blanket certificate authorizing gas sales. Although acknowledging that "only Congress can 'deregulate,' " the Commission "institut[ed] light-handed regulation, relying upon market forces at the wellhead or in the field to constrain unbundled pipeline sale for resale gas prices within the NGA's 'just and reasonable' standard." Order No. 636, ¶ 30,939, at 30,440. The Commission reasoned that open-access transportation, combined with its finding that "adequate divertible gas supplies exist in all pipeline markets," would ensure that the free market for gas sales would keep rates within the zone of reasonableness. *Id.* at 30,437-43; Order No. 636-A, ¶ 30,950, at 30,609-24; Order No. 636-B, ¶ 61,272, at 62,024-25; *see* 18 C.F.R. §§ 284.281-284.288.

The Commission also undertook several measures to ensure that the pipeline grid, or network, functions as a whole in a more competitive fashion. First, open-access pipelines may not inhibit the development of "market centers," which are pipeline intersections that allow customers to take advantage of many more transportation routes and choose between sellers from different natural gas production areas. Similarly, open-access

pipelines may not interfere with the development of "pooling areas," which allow the aggregation of gas supplies at a production area. Order No. 636, ¶ 30,939, at 30,427-28; Order No. 636- A, ¶ 30,950, at 30,581-82; Order No. 636-B, ¶ 61,272, at 62,011-12; *see* 18 C.F.R. §§ 284.8(b)(6), 284.9(b)(5). Finally, as part of the move toward open-access transportation, the Commission required Part 284 pipelines to allow shippers to deliver gas at any delivery point without penalty and to allow customers to receive gas at any receipt point without penalty. Order No. 636, ¶ 30,939, at 30,428-29; Order No. 636-A, ¶ 30,950, at 30,582-86; Order No. 636-B, ¶ 61,272, at 62,012-13; *see* 18 C.F.R. § 284.221(g)-(h).

Even though this is the court's first occasion to address Order No. 636, which was enacted in 1992, we do not write on a clean slate. Beginning with MPC I and MPC II, the court has consistently required the Commission to protect consumers against pipelines' monopoly power. No longer reluctantly engaged in the unbundling enterprise, the Commission has responded by initiating sweeping changes with Order No. 636. Accordingly, we review the Commission's exercise of its authority under the NGA in light of the principles that the court has already applied in this area.

D. *Issues on Review and Conclusions*

After two comprehensive rehearing orders, Orders No. 636-A and No. 636-B, the Commission denied further rehearing.[18]

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18. The Commission has modified its Part 284 regulations in two rulemakings since Order No. 636 that are not on review in this proceeding. First, the Commission adopted further standards for the electronic bulletin boards used for capacity release. Order No. 563, *Standards for Electronic*

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62 F.E.R.C. ¶ 61,007 (1993). The Judicial Panel on Multidistrict Litigation consolidated all the petitions for review of the Order No. 636 series and transferred them to the Eleventh Circuit by random selection pursuant to 28 U.S.C. § 2112(a)(3). On February 15, 1994, the Eleventh Circuit transferred the petitions for review to this court. We consolidated with this case petitions for review of the Commission's decision to prohibit buy/sell agreements,[19] and of the Commission's decision to end capacity-brokering programs.[20] We ordered the petitioners to file briefs in consolidated industry groups: pipelines; local distribution companies (LDCs); small distributors and municipalities; industrial end-users; electric generators; and public utility commissions (PUCs).[21]

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Bulletin Boards Required Under Part 284 of the Commission's Regulations, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,988 (1993) (amending 18 C.F.R. §§ 284.8(b)(4)-(5), 284.9(b)(4)), *order on reh'g*, Order No. 563- A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,994, *reh'g denied*, 68 F.E.R.C. ¶ 61,002 (1994). Second, the Commission modified the short-term exception to the capacity-release rules. Order No. 577, *Release of Firm Capacity on Interstate Natural Gas Pipelines*, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 31,017 (amending 18 C.F.R. § 284.243(h)(1)), *order on reh'g*, Order No. 577-A, [Current] F.E.R.C. Stats. & Regs. ¶ 31,021 (1995).

19. *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,031, *order on reh'g*, 60 F.E.R.C. ¶ 61,117 (1992).

20. *Algonquin Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,032, *reh'g denied*, 60 F.E.R.C. ¶ 61,113 (1992).

21. The court also received separate petitioners' briefs from Carnegie Natural Gas Company, an interstate pipeline company; Elizabethtown Gas Company, a local distribution company; Hadson Gas Systems, Inc., a "marketer" that buys and re-sells pipeline transportation capacity; and Meridian Oil Inc., also a marketer.

Appendix A

The petitioners do not challenge the mandatory unbundling remedy itself. At issue on review are numerous other aspects of Order No. 636 involving changes that the Commission undertook as part of its comprehensive restructuring of the natural gas industry. In Part II of our opinion, we discuss the challenges to the Commission's rules on Part 284 firm transportation. Part III addresses the challenges to the Commission's new capacity-release program. Part IV covers the requirement that pipelines use the straight fixed/variable rate-design methodology. Finally, in Part V we deal with challenges to the Commission's handling of transition costs.

As we discuss in Part II.A, the petitioners challenge four peripheral aspects of the Commission's unbundling remedy. We uphold the Commission's rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer. *See* 18 C.F.R. § 284.14(e). Further, insofar as the Commission may have stated that a § 7(b) abandonment proceeding is never required for pipeline changes to contract-storage withdrawal and injection schedules, we grant relief, but we defer review of possible challenges to specific pipeline changes. The challenge to the Commission's rule that transportation-only pipelines may not acquire capacity on other pipelines has been rendered moot by virtue of an intervening Commission decision. We remand for further explanation the Commission's decision that only those customers who received bundled firm-sales service on May 18, 1992, are entitled to the new no-notice transportation service.

Part II.B concerns the Commission's award of pre-granted abandonment to long-term firm-transportation service, subject to the existing shipper's "right of first refusal" (ROFR). Under this provision of the rules, pipelines are no longer required to

go through § 7 abandonment proceedings when a transportation contract expires. In return, the existing customer has the right to retain service if it matches the terms of a competing offer for that capacity. Such bids are capped at the maximum rate approved by the Commission for that service, and the contract length may not exceed twenty years. Order No. 636, ¶ 30,939, at 30,448-52; Order No. 636-A, ¶ 30,950, at 30,627-36; Order No. 636- B, ¶ 61,272, at 62,025-28; *see* 18 C.F.R. § 284.221(d). While we conclude that in its basic structure the right-of-first-refusal mechanism complies with § 7, we remand the right-of-first-refusal mechanism to the Commission for further explanation of why it adopted a twenty-year term-matching cap. We uphold the Commission's decision not to require pipelines to discount rates in the right-of-first-refusal process.

The Commission also re-visited its policies for the curtailment of gas in times of a supply shortage or a capacity interruption. Gas can be curtailed on an end-use basis, meaning that high-priority users have priority in times of curtailment, or on a pro rata basis, meaning that each user's deliveries are curtailed proportionally. The Commission found that it was statutorily obligated to require pipelines to adopt an end-use curtailment plan for shortages in the supply of pipeline gas. On the other hand, the Commission declined to require pipelines to adopt end-use curtailment for capacity interruption. Order No. 636, ¶ 30,939, at 30,429-31; Order No. 636-A, ¶ 30,950, at 30,586-93. In Part II.C, we affirm the Commission's decision that title IV of the NGPA requires end-use supply curtailment and conclude that the issue of curtailment compensation is not ripe for review. We also deny the petitions for review of the Commission's capacity-curtailment policies, but we do not examine whether pure pro rata capacity curtailment is always appropriate because the Commission has examined that issue

on a pipeline-specific basis in the restructuring proceedings. Finally, we uphold the Commission's policies for supply shortages of third-party gas. Part III addresses the Commission's adoption of a uniform capacity-release program — a regulated market that allows capacity-holders to re-sell the rights to pipeline firm-transportation capacity. An existing shipper that finds itself with excess capacity may list that capacity on the pipeline's electronic bulletin board (EBB), which functions as a central clearinghouse for the secondary capacity market. Order No. 636, ¶ 30,939, at 30,416-21; Order No. 636-A, ¶ 30,950, at 30,550-65; Order No. 636-B, ¶ 61,272, at 61,994-62,003; *see* 18 C.F.R. § 284.243. We uphold the Commission's jurisdiction to regulate the re-sale of interstate-transportation rights in general, as well as specifically its jurisdiction over LDCs who broker capacity to local end-users and over municipal LDCs. We also uphold the Commission's decision that state-authorized "buy/sell arrangements"[22] are pre-empted by the Commission's capacity-release program. Finally, we uphold the Commission's decision to exclude Part 157 shippers and conclude that other challenges to the substance of the capacity-release program are not ripe for review.

Part IV deals with the Commission's requirement that pipelines adopt a new rate-design methodology known as straight fixed/variable (SFV).[23] Under SFV, pipelines must allocate fixed

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22. A buy/sell arrangement is an agreement between an LDC and one of its local end-users under which (1) the end-user identifies (and sometimes purchases) gas held by a producer, (2) the LDC in turn purchases the identified gas and uses its firm-transportation capacity to transport the gas, and (3) the LDC sells the gas to the end-user.

23. The Commission recently issued a policy statement approving the use of market-based rates for transportation services, analogous to the market-

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costs to the reservation charge, and variable costs to the usage charge.[24] The Commission mandated SFV so that fixed costs, which vary greatly between pipelines, would no longer affect the usage charge and thus distort the national gas-sales market that Order No. 636 fosters. Because the shift from the previous modified fixed/ variable (MFV) rate design[25] would disadvantage low-load-factor customers,[26] the Commission adopted various

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based rates for pipeline gas sales, seesupra at 61-62, but only if the pipeline can demonstrate that it lacks significant market power over the transportation service. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076, *reh'g denied*, 75 F.E.R.C. ¶ 61,024 (1996). This policy statement is not on review in this proceeding, and we review only the Commission's requirement that pipelines use SFV rate design.

24. The reservation, or demand, charge is for reserving firm-transportation capacity; the usage, or commodity, charge is for the actual transportation of gas.

25. Under the previously effective MFV rate design, pipelines assigned most fixed costs to the reservation charge, but return on equity and related taxes were assigned along with variable costs to the usage charge. According to one study, the practical result was that under MFV about 15% to 20% of fixed costs were assigned to the usage charge. GENERAL ACCOUNTING OFFICE, NATURAL GAS: COSTS, BENEFITS AND CONCERNS RELATED TO FERC'S ORDER 636, at 33 n.11 (Nov.1993). In addition, under MFV rate design the reservation charge was divided into two equal components: the "D-1 charge" was based on a customer's daily contract demand, or entitlement, and the "D-2 charge" was based on a customer's actual annual usage.

26. A customer's load factor is the ratio between its average usage and its peak usage. Customers with seasonal usage fluctuations, such as LDCs, have low load factors, whereas customers with constant usage throughout the year, such as industrial end-users, have high load factors.

SFV mitigation measures to protect those customers. Order No. 636, ¶ 30,939, at 30,431-37; Order No. 636- A, ¶ 30,950, at 30,593-609; Order No. 636-B, ¶ 61,272, at 62,013-24; *see* 18 C.F.R. § 284.8(d). We uphold the Commission's authority under § 5 to adopt SFV rate design and conclude that substantial evidence supports the Commission's findings that MFV rate design distorted the producer sales market and that SFV is an appropriate rate-design methodology. Although we uphold the Commission's SFV mitigation measures against most challenges, we conclude that the Commission failed to explain why it ordered some mitigation measures on an individual-customer basis and others on a customer-class basis and why it did not require pipelines to offer small-customer discounts to former customers of downstream pipelines. Accordingly, we remand those issues to the Commission.

Finally, as we explain in Part V, the Commission addressed the transition costs involved with implementing Order No. 636. The Commission allowed pipelines, whose role as gas merchants was greatly reduced, to pass through to transportation customers all the costs of reducing contractual purchase obligations from producers, known as gas-supply realignment (GSR) costs. Unlike the Order No. 500 equitable-sharing cost-recovery mechanism for take-or-pay costs from pipeline-producer contracts, Order No. 636 imposes all the costs of realigning unneeded producer-pipeline contracts on pipeline customers. The Commission authorized pipelines to recover 90% of the GSR costs from current firm-transportation customers (including customers who converted from being bundled firm-sales customers under Order No. 436) and 10% of the GSR costs from interruptible-transportation customers. Order No. 636, ¶ 30,939, at 30,457-62; Order No. 636-A, ¶ 30,950, at 30,641-64; Order No.636-B, ¶ 61,272, at 62,031-45. We uphold the Commission's decision

to allow pipelines to recover GSR costs from customers who converted to open-access transportation before Order No. 636, but remand the decision that pipelines must allocate 10% of GSR costs to interruptible-transportation customers for further explanation. We also remand the decision that pipelines can pass through all their GSR costs to customers for further consideration by the Commission in light of the equitable-sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636. We affirm the Commission's treatment of LDC by-pass, GSR costs for the Great Plains coal gasification project, and stranded costs.

The Commission resolved issues that it considered generic to all pipelines in the Order No. 636 rulemaking, but deferred many issues associated with the implementation of mandatory unbundling to restructuring proceedings. Every Part 284 pipeline is required to go through an individual pipeline restructuring proceeding, to conform its operations to the new regulations and to address pipeline-specific issues. 18 C.F.R. § 284.14; Order No. 636, ¶ 30,939, at 30,462-69; Order No. 636-A, ¶ 30,950, at 30,664-73. The Commission has by now completed the restructuring proceedings, and in the proceedings for some pipelines interested parties have petitioned for review.[27] In this decision, we review only the Order No. 636 rulemaking, although on some issues we have necessarily had to consider the interaction between the rulemaking and the subsequent restructuring proceedings.

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27. The court has docketed the petitions for review of the restructuring proceedings in *UGI Utilities v. FERC*, No. 93-1291, and held them in abeyance until our decision.

II. Open-Access Firm Transportation

A. *Unbundling*

The petitioners challenge four aspects of the Commission's unbundling remedy: the rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer; the Commission's policy on pipelines' ability to modify existing storage contracts without abandonment proceedings; the rule that transportation-only pipelines may not acquire capacity on other pipelines; and the eligibility date for no-notice transportation service.

1. *Prohibition on unilateral customer release of transportation capacity*

When the Commission concluded that the pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA, Order No. 636, ¶ 30,939, at 30,405, the Commission found also that "the continued enforcement of a pipeline sales customer's purchase obligations, agreed to before implementation of unbundling under this rule, is unjust and unreasonable, and unduly discriminatory." *Id.* at 30,453. Accordingly, all existing bundled firm-sales customers were given the option to reduce or terminate their contractual purchase obligations during the pipeline's restructuring proceedings. 18 C.F.R. § 284.14(d)(1). By contrast, those customers were not relieved of their contractual transportation obligations unless either an alternative, creditworthy shipper offered to assume the capacity at the same or a higher rate (up to the maximum approved rate), or the pipeline agreed to reduce or terminate the transportation obligation. *Id.* § 284.14(e)(2). If a customer wished to reduce or terminate its transportation obligation, and either a

replacement shipper assumed the capacity or the pipeline agreed, then the pipeline was authorized to abandon the service under the prior contract. *Id.* § 284.14(e)(3). In effect, existing bundled firm-sales customers remained contractually bound to receive firm-transportation service on the pipeline. On rehearing, Northern Indiana Public Service Company (NIPSCO) maintained that the Commission's actions entirely abrogated the existing pipeline-customer bundled firm-sales contracts, and that the Commission could not require the LDCs to enter into new transportation contracts. The Commission denied that it had abrogated the contracts: the pipelines remained contractually obligated to provide separate sales and transportation services. "[T]he fact that LDCs have an opportunity to revise their sales entitlements under existing contracts with their pipeline suppliers does not mean they should also have an unqualified right to terminate their obligations for the costs of transportation capacity under those contracts." Order No. 636-A, ¶ 30,950, at 30,638. The Commission also explained that if it released former bundled-sales customers from transportation obligations, "these capacity costs could be shifted from the customer who has contracted for the capacity to the pipeline or other customers that have no need for the capacity." *Id.* at 30,637.

NIPSCO, joined by other LDC petitioners,[28] contends that, by holding pipeline customers to the transportation component of bundled firm-sales contracts, the Commission essentially imposed a new contract upon the customers, which is beyond the Commission's § 5 authority. Section 5(a) provides that, whenever the Commission has found that an existing contract is "unjust, unreasonable, unduly discriminatory, or preferential," it "shall determine the just and reasonable contract to be

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28. The other LDC petitioners are the Atlanta Gas Light Company and the Chattanooga Gas Company.

thereafter observed and in force, and shall fix the same by order." 15 U.S.C. § 717d(a). NIPSCO contests not the Commission's underlying finding that the bundled firm- sales contracts violated §§ 4(b) and 5(a), but only the remedy imposed under § 5. Our review is limited to whether the Commission's reading of § 5 to authorize it to hold LDCs to the remaining terms of a modified pipeline-customer contract is a reasonable construction of its statutory authority. *See AGD I*, 824 F.2d at 1001.

The bundled firm-sales contracts between pipelines and LDCs were subject to the Commission's § 5 authority. The regulatory structure of the Natural Gas Act is contract-based: it "permits the relations between the parties to be established initially by contract, the protection of the public interest being afforded by supervision of the individual contracts." *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 339, 76 S.Ct. 373, 378, 100 L.Ed. 373 (1956). Under § 5, "the Commission has plenary authority to limit or to proscribe contractual arrangements that contravene the relevant public interests." *Permian Basin Area Rate Cases*, 390 U.S. 747, 784, 88 S.Ct. 1344, 1369, 20 L.Ed.2d 312 (1968). For example, in *Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C.Cir.1985), *cert. denied*, 476 U.S. 1114, 106 S.Ct. 1968, 1969, 90 L.Ed.2d 653 (1986), the court affirmed the Commission's decision in Order No. 380 that "minimum bill" provisions in existing contracts were "unjust and unreasonable" under § 5.[29] The court upheld

29. Minimum bills were clauses in pipeline-customer contracts that "require[d] a pipeline customer to pay for a minimum volume of gas, whether or not the customer purchase[d] that amount of gas." *Wisconsin Gas Co.*, 770 F.2d at 1149. Thus, the minimum bills were analogous to the take-or- pay provisions in pipeline-producer contracts. But cf. *id.* at 1159-60. The Commission prohibited minimum bills because they allowed pipelines to collect substantial commodity charges for gas that was never delivered and

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the Commission's remedy, eliminating the minimum bill from the contracts, against the claim that such a remedy "unlawfully alter[ed] the terms of existing contracts," on the ground that "section 5 gives the Commission authority to alter terms of any existing contract found to be 'unjust' or 'unreasonable.' " *Id.* at 1153 n. 9.

NIPSCO also maintains that the Commission has construed its § 5 authority to extend beyond the limits in § 1(b) on the Commission's jurisdiction. Regardless of the Commission's authority to impose modified contractual obligations on pipelines, NIPSCO contends that the Commission lacks such authority over LDCs because LDCs are "non-jurisdictional" entities. Under § 1(b), the Commission's jurisdiction over "the transportation of natural gas in interstate commerce" does not apply to "the local distribution of natural gas or to the facilities used for such distribution." 15 U.S.C. § 717(b). But the local-distribution exception applies only to the movement of gas within an LDC's local mains and not to the movement of gas in high-pressure interstate pipelines. *FPC v. East Ohio Gas Co.*, 338 U.S. 464, 470-71, 70 S.Ct. 266, 269-70, 94 L.Ed. 268 (1950); *see also Louisiana Power & Light*, 406 U.S. at 636 & n. 13, 92 S.Ct. at 1836 & n. 13. Thus, for the same reasons that the

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because they "ha[d] become a major obstacle to the transmittal of clear market signals from the burner tip back to the well-head." Order No. 380, *Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,571, at 30,962, *order on reh'g*, Order No. 380-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,584, *order on reh'g*, 29 F.E.R.C. ¶ 61,076, *order on reh'g*, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,607, *order on reh'g*, 29 F.E.R.C. ¶ 61,332 (1984), *affirmed in part and remanded in part sub nom. Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C.Cir.1985).

Commission has jurisdiction over the re-sale of interstate capacity rights by LDCs to local end-users, *see infra* Part III.B.2, it also has jurisdiction over an LDC's ability to reduce or terminate its contractual interstate-transportation obligation. The pipeline-LDC contracts for transportation through interstate pipelines do not fall within the local-distribution exception to the Commission's jurisdiction.

The Commission cannot use the pipeline-LDC contracts as a jurisdictional hook for non-jurisdictional measures that do not relate to the Commission's § 5 remedial authority over the contracts.[30] As the court has held in a different context, the Commission may not assert its jurisdiction over a party merely because it is "involved in a contractual relationship with a jurisdictional pipeline." *ARCO Oil & Gas Co. v. FERC*, 932 F.2d 1501, 1503 (D.C.Cir.1991). NIPSCO maintains that the Commission has done just that by replacing the agreed-upon contractual terms with entirely new terms of the Commission's own devising, when it would otherwise be without jurisdiction to compel the LDC to receive service in the first instance. But we do not agree that the Commission has overstepped the bounds of its § 5 authority in the first place. First, an LDC may maintain its original bargain by choosing not to exercise its unilateral right to terminate the purchase obligation. The resulting combination of sales service and no-notice firm-transportation service replicates its prior contractual entitlement. Thus, it is somewhat difficult to see the purported compulsion against LDCs in the Commission's decision not to grant them the right to terminate their transportation obligations. Second, the Commission's remedy was appropriately confined to the underlying violation. Because the Commission found the sales component of the bundled contracts to be unjust and

30. *See also infra* at 91 n. 57.

unreasonable, Order No. 636, ¶ 30,939, at 30,453, it interfered with existing contracts only to the extent necessary to remedy the effects of pipelines' market power. The Commission has the authority under § 5 to adopt a remedy proportionate to the problem being addressed. *AGD I*, 824 F.2d at 1019. Finally, § 5 instructs that "the Commission shall determine the just and reasonable . . . contract to be thereafter observedand in force, and shall fix the same by order." 15 U.S.C. § 717d(a). The limits of the Commission's authority to modify pipeline-LDC contracts under § 5 lie in the requirement that, given the original contract and the Commission's findings of unlawfulness, the resulting contract be "just and reasonable." NIPSCO does not contend that the result of unbundling the firm-sales contracts was unjust or unreasonable. We therefore uphold the Commission's § 5 authority to hold LDCs to the transportation component of the modified bundled firm-sales contracts.

NIPSCO contends in the alternative that, even if the Commission's action was within its § 5 authority, the Commission acted arbitrarily and capriciously. In NIPSCO's view, the limited nature of the remedy allows pipelines to continue to exercise market power over customers in the transportation contracts, in contravention of the overall goals of Order No. 636. We reject this challenge as well because the Commission has provided a reasonable basis for its decision not to allow customers unilaterally to reduce their contractual transportation obligations. *Cf. ARCO*, 932 F.2d at 1502.

The Commission found in Order No. 636 that "the amount of capacity reserved for pipeline firm sales still far exceeds the pipelines' actual sales so that capacity is not available for firm transportation and, as a result, interruptible transportation maintains a significant share of peak period transportation."

Order No. 636, ¶ 30,939, at 30,406. In other words, because many firm-sales customers decided to purchase third-party gas and transport it using interruptible service, those customers ended up holding excess reserved capacity. NIPSCO asserts that the effect of the Commission's decision not to allow LDCs unilaterally to reduce their contractual transportation obligations is to perpetuate customers' excessive capacity holdings. NIPSCO is correct insofar as the effect of any contract is to lock in current conditions, and the existence of a long-term contract necessarily slows the transition of a market to a new equilibrium when some underlying condition changes. Moreover, the capacity-release mechanism is an imperfect solution for the LDCs because the existing pipeline customer is unlikely to receive full compensation for released capacity in an excess-capacity market situation. Yet the problem of capacity excess that the Commission identified was that customers held more capacity in bundled-sales contracts than they purchased gas from the pipeline, not that customers held more firm-transportation capacity than needed for their peak demand. Contrary to NIPSCO's contention, there is no contradiction between the general goal in Order No. 636 of encouraging more efficient use of reserved capacity and the challenged rule that customers may not unilaterally release contractual transportation obligations: the Commission never found that the natural gas industry after mandatory unbundling would be characterized by excess reserved capacity.

Moreover, the Commission provided in Order No. 636-A a coherent rationale for its decision. Because a pipeline's rate structure is predicated upon levels of reserved capacity, providing customers with the unilateral option to reduce those levels would either reduce the pipeline's cost recovery or force

the pipeline to increase rates for the remaining customers.[31] Order No. 636- A, ¶ 30,950, at 30,637. Because someone has to bear the costs of unfavorable contractual capacity obligations, the Commission reasoned that the customer who voluntarily assumed those obligations by entering into the contract should bear those costs rather than spreading them over all of the pipeline's customers.

The Commission decided to modify the set of contracts that forms the structure of the natural gas industry only as much as necessary to alleviate the anti-competitive sales component of the bundled contracts. The Commission is not required to exercise its § 5 authority beyond the limits of the problem it has identified, *see AGD I*, 824 F.2d at 1019, and its cost-shifting rationale was a well-reasoned justification for its decision not to go further. We therefore uphold this portion of the rules.

2. *Pipeline modification of contract-storage rights*

Because the Commission found that "pipelines' superior rights with respect to access and control provide them with several advantages over other gas merchants with no access to storage for their gas," it required pipelines to offer access to their storage capacity on an open-access basis. Order No. 636, ¶ 30,939, at 30,425-26. By defining "transportation" to include "storage," 18 C.F.R. § 284.1(a), the Commission made storage subject to the same non-discrimination requirements as capacity

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31. The Commission also announced that the customer could negotiate an "exit fee" to induce the pipeline to release the customer from its contractual obligations. Order No. 636, ¶ 30,939, at 30,454. Whether the customer retains excess contractual capacity or negotiates a one-time exit fee, however, there is no reason why the cost to the customer should not be the same, discounted over time.

rights. *Id.* §§ 284.8(b), 284.9(b). Although pipelines were allowed to retain storage capacity for system management and in order to ensure the delivery of no-notice service, they were required to offer remaining storage capacity on an open-access contractual basis for customer-owned gas. Order No. 636, ¶ 30,939, at 30,426- 27. The Commission granted former bundled firm-sales customers a priority right to that storage capacity. Order No. 636-A, ¶ 30,950, at 30,578.

In its request for rehearing of Order No. 636, CNG Transmission Corporation, a pipeline company, explained that the changes involving open-access storage would create difficulties for it in providing the contractual levels of service to its existing contract-storage customers. Because "current contract storage injection and withdrawal schedules, and other related operational protocols, are based upon current levels of contract storage service," CNG requested the ability to modify existing storage customers' contractual rights to inject or withdraw gas. The Commission responded that its

> intent was that current contract storage customers retain their full right to capacity as specified in their contracts. The Commission did not mean to infer [sic] that the terms and conditions associated with their rights could not be changed if they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage. This, of course, is a pipeline specific matter and must be addressed in the restructuring proceeding.

Order No. 636-A, ¶ 30,950, at 30,579. Upon further rehearing, however, the Commission went further, stating that,

> while it has authorized pipelines to propose to change existing storage arrangements, if necessary, to provide no-notice transportation service, the pipeline must still show that the changes are necessary and reasonable. This includes an impact of a change on current contract storage customers. The Commission has not authorized any reduction in contract storage capacity. The Commission views changes to injection and withdrawal schedules as changes to terms and conditions, rather than to the level of certificated service. Hence, the Commission concludes that changes to existing contract storage terms and conditions will not need action under NGA section 7(b).

Order No. 636-B, ¶ 61,272, at 62,011.

A group of LDC petitioners[32] challenges the Commission's statement that changes to contract-storage withdrawal and injection schedules do not require a § 7(b) abandonment proceeding. We agree with the petitioners that it is difficult to discern exactly what the Commission's position is on this issue, and we grant the petitioners relief insofar as the Commission stated in Order No. 636-B that any change to injection and withdrawal schedules can be effected without a § 7(b) abandonment proceeding.

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32. The LDC petitioners are the Associated Gas Distributors, the Atlanta Gas Light Company, the Chattanooga Gas Company, the Brooklyn Union Gas Company, Elizabethtown Gas Company, and Long Island Lighting Company.

If the Commission has permitted the pipelines to "abandon" a "service rendered by means of . . . facilities" certificated by the Commission, then it has failed to comply with § 7(b), which requires a "due hearing" and a Commission finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). In general, the test for § 7 abandonment is whether the certificate-holder "permanently reduces a significant portion of a particular service." *Reynolds Metals Co. v. FPC*, 534 F.2d 379, 384 (D.C.Cir.1976); *see also Kansas Power & Light Co. v. FERC*, 851 F.2d 1479, 1481 (D.C.Cir.1988). By comparison, the withholding of gas delivery to an interruptible-transportation customer is not an "abandonment," because the customer has no right to guaranteed delivery under its contract or the certificate of service. *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 129-30 (D.C.Cir.1982). Although the court has reserved the issue whether a § 7(b) abandonment occurs when only the identity of the customer changes, an abandonment does take place "when there is a reduction or alteration in overall service." *Tennessee Gas Pipeline Co. v. FERC*, 972 F.2d 376, 384 (D.C.Cir.1992).

According to the submissions by the Associated Gas Distributors in the administrative record, a customer who contracts for storage is concerned with two elements: capacity (how much gas can be stored) and deliverability (how much gas can be withdrawn on a given day).[33] The AGD attached affidavits

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33. The Commission has defined these terms as follows:

> [I]n contracting for storage, a customer reserves a specific level of deliverability, capacity, and injection/withdrawal services. Deliverability reflects the right of the storage customer to call on the delivery capacity

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from six member LDCs who stated that changes to injection and withdrawal schedules could reduce deliverability, with adverse consequences on their ability to meet residential customers' demands. Elizabethtown Gas Company, in its opposition to CNG's compliance filing in its restructuring proceeding, objected to CNG's specific proposals to reduce withdrawal amounts when contract-storage customers had low gas inventories in storage, to maintain elevated minimum inventory levels during the early winter months, to limit monthly withdrawal amounts to less than the total of the daily amounts, to reduce firm withdrawal rights to best-efforts rights, and to impose minimum inventory turnovers.

It is impossible, on the current record, to determine on a generic basis what changes to injection and withdrawal schedules would "permanently reduce[ ] a significant portion" of contract-storage service. *Reynolds Metals*, 534 F.2d at 384. Because contractual deliverability entitlements are an integral part of the customer's contract-storage rights, modifications that affect those rights could in some instances constitute a § 7 abandonment. On the other hand, under other circumstances an adjustment to an injection or withdrawal schedule could be sufficiently minor or temporary that no abandonment would occur. Whether an abandonment proceeding is necessary depends on the individual customer's storage contract and on the pipeline's proposed modifications, none of which are before us now.

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> of the storage facilities every day for a specified level of daily contract deliverability. Injection/withdrawal is the injection and withdrawal of gas from storage.

Consolidated Gas Transmission Corp., 47 F.E.R.C. ¶ 61,171, at 61,563, *order on reh'g*, 49 F.E.R.C. ¶ 61,041 (1989).

Appendix A

To the extent that the Commission issued in Order No. 636-B a sweeping statement that no modifications to injection and withdrawal schedules for a contract-storage customer require an abandonment proceeding, such a statement is inconsistent with § 7. In its brief, however, the Commission denies that it has taken any such steps to degrade contract-storage rights. Instead, the Commission maintains that it has merely allowed pipelines to propose "necessary and reasonable" changes in the restructuring proceedings, Order No. 636-B, ¶ 61,272, at 62,011, for which the Commission has authority under § 5. In the restructuring proceedings, the Commission has followed this approach, approving proposed modifications to withdrawal and injection schedules if the pipeline can prove that the changes are "necessary and reasonable."[34]

The Commission's theory that it has the authority to proceed in the restructuring proceedings under § 5 rather than in abandonment proceedings under § 7(b) is explained nowhere in the Order No. 636 series. *See* Order No. 636-A, ¶ 30,950, at 30,579; Order No. 636-B, ¶ 61,272, at 62,011. Under § 7(b), the Commission must hold a "due hearing" and must make a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). By contrast, under § 5 the Commission need hold only a "hearing" and must find that an existing contract is "unjust, unreasonable,

34. *See, e.g., Equitrans, Inc.*, 63 F.E.R.C. ¶ 61,009, at 61,064, *order on reh'g*, 64 F.E.R.C. ¶ 61,155, at 62,238, *order on reh'g*, 65 F.E.R.C. ¶ 61,132 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,235 (1994), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C.Cir.); *ANR Pipeline Co.*, 62 F.E.R.C. ¶ 61,079, at 61,527-28, *order on reh'g*, 64 F.E.R.C. ¶ 61,140, at 62,006, *order on reh'g*, 65 F.E.R.C. ¶ 61,162 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,340, *order on reh'g*, 68 F.E.R.C. ¶ 61,009 (1994), *order on reh'g*, 71 F.E.R.C. ¶ 61,033 (1995), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C.Cir.).

unduly discriminatory, or preferential." *Id.* § 717d(a). We need not decide whether compliance with the procedures in § 5 could in certain circumstances satisfy the applicable statutory requirement in § 7(b). The Commission has assured us in its brief that its approach under § 5 will be "consistent" with the § 7 requirements. But without any explanation in the Order No. 636 decisions for why the Commission's procedures satisfy § 7(b), we cannot accept the Commission's suggestion that its exercise of its § 5 authority in the restructuring proceeding would obviate the need for abandonment hearings.

On the other hand, any claim that a particular pipeline's modification to contract-storage withdrawal and injection schedules requires a § 7(b) abandonment proceeding is premature and should be raised, if at all, in the review of individual restructuring proceedings.[35]

3. *Capacity retention by transportation-only pipelines*

A central part of the Commission's unbundling program is the requirement that all pipelines assign to their firm-transportation customers the firm-transportation capacity that the pipelines held on upstream pipelines. 18 C.F.R. § 284.242. Now that customers can buy gas directly from the producers, they may bear the responsibility of reserving capacity both on "upstream" and "downstream" pipelines.[36] If the downstream

35. The LDC petitioners object that the Commission lacked substantial evidence to support the required showing under § 5 that existing contract-storage service was not "just and reasonable." We similarly defer any review of this claim until applied in a concrete situation in a restructuring proceeding.

36. An "upstream" pipeline is located closer to the wellhead, or production area. A "downstream" pipeline is located closer to the burner- tip, or the end-user.

pipeline were allowed to retain the capacity on the upstream pipeline, the Commission reasoned, it would inhibit the formation of a competitive gas-sales market by preventing downstream customers from gaining access to the new opportunity to purchase gas directly from the producers. Order No. 636, ¶ 30,939, at 30,417-18.

Two pipeline petitioners, ANR Pipeline Company and Colorado Interstate Pipeline Company, urge the Commission to carve out an exception for "transportation-only pipelines" — pipelines that do not offer any gas sales. For example, a downstream pipeline may wish to offer a customer a package of firm-transportation capacity on its pipeline as well as on a connecting upstream pipeline; the customer may well prefer not to have to contract separately with the upstream pipeline.

This petition for review has been rendered moot by an intervening declaratory order. In *Texas Eastern Transmission Corp.*, 74 F.E.R.C. ¶ 61,074, at 61,220 (1996), *reh'g pending*, Docket No. CP 95-218, the Commission declared that the successful completion of unbundling under Order No. 636, with the separation of pipelines' merchant and transportation functions, had alleviated the Commission's former concerns that pipelines would obstruct access to production areas to favor their merchant functions. Accordingly, the Commission announced that it would "decide whether to allow pipelines to acquire upstream or downstream capacity on a case-by-case basis." *Id.* The Commission's intervening action appears to have provided the pipeline petitioners with the relief that they had sought; any further relief is available in review of the declaratory-order proceeding.

4. *Eligibility date for no-notice transportation*

In its new regulation, the Commission requires interstate pipelines "that provided a firm sales service on May 18, 1992" to offer no-notice transportation service. 18 C.F.R. § 284.8(a)(4). In Order No. 636-A, the Commission clarified that "[t]he pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no- notice firm, city-gate, sales service on May 18, 1992." Order No. 636-A, ¶ 30,950, at 30,573. Although several commentators requested the Commission to require pipelines to extend no-notice transportation service to customers who had already converted from bundled firm-sales service under Order No. 436 and consequently no longer received such service on May 18, 1992, the Commission denied rehearing. The Commission offered three reasons: first, that it was prudent to begin the experiment with no-notice transportation on a limited basis; second, that customers who were not receiving bundled firm-sales service on May 18, 1992, "were not relying on that service"; and third, that such customers "could not reasonably expect to receive no-notice transportation in the future" because neither Order No. 436 nor the Notice of Proposed Rulemaking for Order No. 636 had contemplated it. Order No. 636-B, ¶ 61,272, at 62,007.

The National Association of Gas Consumers (NAGC) contends that the ineligibility of former bundled firm-sales customers who converted to open- access transportation under Order No. 436 to receive no-notice transportation is unduly discriminatory.[37] NAGC relies on the Commission's own

37. NAGC frames its argument in terms of "small" customers and confuses in its brief the distinct issues of small-customer rates (one-part rates at an imputed load factor) and no-notice transportation service. In fact, the

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regulation, promulgated by Order No. 436, which requires an open-access pipeline to offer service "without undue discrimination." 18 C.F.R. § 284.8(b)(1). And as NAGC points out, the Commission found in Order No. 636 that the pipelines' open-access firm-transportation service under Order No. 436 was unlawfully discriminatory because it did not provide the same quality of transportation service as was available with bundled firm-sales service. Order No. 636, ¶ 30,939, at 30,402. Now, customers who converted under Order No. 436 remain limited to stand-alone firm-transportation service subject to scheduling and balancing requirements and other penalties. Thus, NAGC maintains that the Commission must extend eligibility for no-notice transportation service to customers who converted before Order No. 636 in reliance on the non-discrimination provisions.

We find the Commission's justifications in Order No. 636-B unconvincing. The Commission's desire to proceed cautiously with no-notice transportation, rather than require pipelines to offer it to all customers, cannot explain the disadvantaging of former bundled firm-sales customers who converted under Order No. 436. Although those customers had no right to expect to receive no-notice transportation service under Order No. 636, neither did customers who did receive bundled firm-sales service on May 18, 1992. Finally, the Commission has not provided substantial evidence to support its assumption that bundled firm-

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availability of no-notice transportation service does not depend on a customer's size. NAGC's argument about small-customer rates fails because eligibility for small-customer rates is determined by customer class, so any pipeline that offered small-customer rates on May 18, 1992, must continue to offer such rates "on the same basis" to all customers. Order No. 636-A, ¶ 30,950, at 30,600.

sales customers who retained bundled service relied more heavily on reliability of transportation service than did customers who switched to open-access transportation. We therefore remand this issue to the Commission for further explanation of which customers should be eligible for no-notice transportation service.

B. *Right of First Refusal*

Section 7(b) of the Natural Gas Act prohibits pipelines from abandoning certificated firm-transportation service until the Commission makes a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). In its original adoption of open-access transportation in Order No. 436, the Commission provided automatic "pre-granted abandonment"[38] for all firm-transportation service provided under a Part 284 blanket certificate. 18 C.F.R. § 284.221(d) (1989). After the order was twice vacated on other grounds,[39] the Commission re-promulgated the automatic pre-granted abandonment rule in Order No. 500-H, ¶ 30,867, at 31,583- 85. In its review of Order No. 500-H, the court remanded automatic pre-granted abandonment because "the Commission has not yet adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation — protection of gas customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period." *AGA II*, 912 F.2d at 1518. In *AGA II*, the court concluded that

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38. A natural gas company that receives "pre-granted abandonment" of a certificated service need not undergo the customary § 7 abandonment public convenience and necessity.

39. Order No. 436 was vacated by *AGD I* in 1987. Then Order No. 500 was vacated by *AGA I* in 1989. *See supra* Part I.B.

the Commission's reliance on various market alternatives available to LDCs — namely interruptible transportation, stand-by gas service and gas from alternative suppliers — provided inadequate protection for LDCs. *Id.* at 1517. The court similarly rejected the Commission's contention that it was furthering purposes other than the protection of existing customers because "the Commission's response seems to entail an enormous qualification of its basic purpose." *Id.* On remand from AGA II, the Commission decided to hold the issue of pre-granted abandonment in abeyance until Order No. 636. *See* Order No. 500-J, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,915 (1991).

In Order No. 636, the Commission responded to *AGA II* by amending its regulations to provide that an existing customer of long-term firm- transportation service could avoid pre-granted abandonment if it abided by a new right-of-first-refusal (ROFR) mechanism. 18 C.F.R. § 284.221(d). No petitioner challenges the Commission's rule that interruptible transportation, and firm transportation with a contract term of less than one year, are subject to automatic pre-granted abandonment even without the right of first refusal. Order No. 636, ¶ 30,939, at 30,446; Order No. 636-A, ¶ 30,950, at 30,625-26. But the petitioners do challenge pre-granted abandonment for long-term firm transportation. In essence, the issue is whether the right-of-first-refusal mechanism provides the protection for pipeline customers that *AGA II* requires.

The right-of-first-refusal mechanism consists principally of two matching requirements: rate and contract term. *See* 18 C.F.R. § 284.221(d)(2)(ii). Near the end of a long-term firm-transportation contract, the existing customer may notify the pipeline that it intends to exercise its right of first refusal. The pipeline must post the availability of that capacity on its

electronic bulletin board and, in accordance with the criteria set forth in its tariff, identify the "best bid" offered by any competing shippers. Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. The customer then has the right to match the competing bid's rate, up to the maximum "just and reasonable" rate that the Commission has approved for that service, and the competing bid's contract term. Competing shippers may choose to bid for only a portion of the capacity in the expiring contract. Order No. 636, ¶ 30,939, at 30,451-52; Order No. 636-A, ¶ 30,950, at 30,634- 35. The Commission promised that it would scrutinize competing bids from pipelines' marketing affiliates to ensure that they did not collude to increase the bidding level.[40] Order No. 636, ¶ 30,939, at 30,451; Order No. 636- A, ¶ 30,950, at 30,634.

Originally, the Commission contemplated that competing bids could be for any contract length. According to the Commission, "[o]ther things being equal, the satisfaction of long-term transportation needs should have priority over the satisfaction of shorter-term needs." Order No. 636, ¶ 30,939, at 30,450. In Order No. 636-A, the Commission reconsidered that decision and found

> that capping the contract term that must be matched by a customer exercising its right of first refusal at a period of 20 years strikes an appropriate balance between the pipeline's

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40. The Commission exempted from pre-granted abandonment the firm-transportation capacity of any customer who converted from bundled firm-sales service between February 13, 1991 (the effective date of Order No. 500-J) and May 18, 1992 (the effective date of Order No. 636). 18 C.F.R. § 284.221(d)(3); *see* Order No. 636, ¶ 30,939, at 30,452; Order No. 636-A, ¶ 30,950, at 30,635-36.

> need for stability, the customer's need for flexibility, and the Commission's overall goal in Order No. 636 to foster long- term, market driven arrangements in the gas industry. This cap, in the Commission's judgement, ensures that the customer obtaining the service values the service sufficiently to commit to using it for a reasonable period and provides the pipeline with a reasonable level of stability. Twenty years has been the traditional length of long-term contracts in the natural gas industry and a number of recent contracts for new capacity are for a twenty year term.

Order No. 636-A, ¶ 30,950, at 30,631. Commissioner Moler, dissenting in part, characterized the twenty-year period as "a blatantly anti-LDC rule," given that LDCs typically have existing contractual relationships jeopardized by pre-granted abandonment, and urged the adoption of a shorter contract-term cap. *Id.* at 30,678-79.

1. *Pre-granted abandonment generally*

Many of the petitioners[41] contend that the Commission's pre-granted abandonment of firm-transportation service violates § 7. The petitioners maintain that the right-of-first-refusal

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41. The petitioners on this issue include the Industrial End-User petitioners (the Process Gas Consumers Group, the American Iron and Steel Institute, the Georgia Industrial Group, the American Forest and Paper Association, Arcadian Fertilizer, and the Virginia Electric and Power Company), the American Public Gas Association, the National Association of Gas Consumers, and three LDC petitioners (Atlanta Gas Light Company, Chattanooga Gas Company, and NIPSCO).

mechanism provides inadequate protection to existing pipeline customers from the pipelines' market power.

The Commission may satisfy its § 7 obligations by making generic findings of public convenience and necessity. In *Mobil Oil Exploration & Producing Southeast Inc. v. United Distribution Cos.*, 498 U.S. 211, 227, 111 S.Ct. 615, 625, 112 L.Ed.2d 636 (1991), the Supreme Court upheld a pre-granted abandonment scheme under the Commission's Order No. 451, even though the Commission's "approval is not specific to any single abandonment but is instead general, prospective, and conditional." *See also FPC v. Moss*, 424 U.S. 494, 499-502, 96 S.Ct. 1003, 1007-08, 47 L.Ed.2d 186 (1976). The Court approved the Commission's findings that, under its good- faith negotiation procedures for the pre-granted abandonment of producers' sale of "old gas" under the NGPA to pipelines, pipelines would be protected "by allowing them to buy at market rates elsewhere if contracting producers insisted on the new ceiling price." *Mobil Oil*, 498 U.S. at 227, 111 S.Ct. at 626. In *AGA II*, by contrast, the court held that the Commission had not adequately explained why pre-granted abandonment of firm-transportation in Order No. 500-H would not "allow pipelines indirectly to extract monopoly profits from their customers." 912 F.2d at 1516. Most important, the Commission's proposed alternatives to existing firm-transportation service, such as interruptible transportation and stand-by service, failed to provide the existing customer with an adequate level of protection. *Id.* at 1517. From *Mobil Oil* and *AGA II*, we conclude that, for a finding of public convenience and necessity for pre-granted abandonment under § 7, the Commission must make appropriate findings that existing market conditions and regulatory structures protect customers from pipeline market power.

Appendix A

The Commission's initial protective measures — contractual "evergreen" or "roll-over" clauses — are by themselves inadequate. The Commission allows the pipeline and the customer to negotiate such a contractual provision allowing the parties to extend the contract before termination and thereby avoid the abandonment issue. Moreover, the Commission requires pipelines that offer evergreen or roll-over clauses to do so on a non-discriminatory basis. Order No. 636-A, ¶ 30,950, at 30,628. Yet the Commission declined to mandate the inclusion of contract-extension clauses. *Id.* As the petitioners note, the voluntary nature of evergreen and roll-over clauses means that those pipelines that do enjoy market power will likely refuse to offer such clauses to their customers. Thus, voluntary contract-extension clauses alone do not provide sufficient protection to existing pipeline customers.

The mandatory right-of-first-refusal mechanism, however, provides substantially more protection to existing customers.[42]

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42. The Commission also provided that its

> complaint procedure is always available to remedy an unjustified loss of service. A hearing is necessary, however, only when there are material facts in dispute. As the Commission has explained, the right of first refusal is an adequate protection for LDCs serving core customers.

Order No. 636-A, ¶ 30,950, at 30,633. Although the petitioners object that the complaint process, 18 C.F.R. § 385.206, provides inadequate protection, it is evident that the Commission intended the complaint process to serve only as a back-up to the right-of-first-refusal mechanism. We do not address the petitioners' contention, made for the first time at oral argument, that the Commission should have adopted a complaint procedure modeled after 18

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First, shippers bid against one another for capacity, which in the Commission's view will prevent the pipeline from using the right-of-first-refusal mechanism to push the rate above the competitive market price.[43] Second, under the right-of-first-refusal mechanism the competing bid is capped at the maximum "just and reasonable" rate, which protects the existing shipper from having to match a bid higher than the Commission-approved rate. If the existing customer is willing to pay the maximum approved rate, then the right-of-first-refusal mechanism ensures that the pipeline may not abandon the certificated service. In this way, even a captive customer served by a single pipeline can exercise its right of first refusal and retain its long-term firm-transportation service against rival bidders. Hence, the basic structure of the right-of-first-refusal mechanism provides the protections from pipeline market power required for pre-granted abandonment under § 7.

2. *The twenty-year contract term*

The petitioners also contend that the contract term-matching condition allows pipelines to exercise market power inconsonant

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C.F.R. § 157.106, which allows customers to contest the pre-granted abandonment of optional expedited certificates (an innovation of Order No. 436 in which the Commission presumes that an application for a "new service" meets the public convenience and necessity if the pipeline agrees to bear the full economic risk, *see AGD I*, 824 F.2d at 1030-31).

43. The Commission decided not to specify on a generic basis the appropriate method for pipelines to use in determining the "best bid." *See* Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. Rather, as the Commission stated, it can guard against such pipeline influence in its review of the individual restructuring proceedings and pipeline tariff filings.

with pre-granted abandonment. Thus, on capacity-constrained pipelines existing customers may be forced to match competing bids for twenty years' duration, which would not be the outcome in a competitive market without pipelines' natural monopoly. Competing bidders who come up against the rate ceiling for this scarce resource — capacity on constrained pipelines — may bid up the length of the contract term to try to win the auction. In effect, bidding for a longer contract term becomes a surrogate for bidding beyond the maximum rate level. Especially with the new capacity-release mechanism, a competing bidder could bid for a longer contract term than it would contract for in a competitive market, release the excess capacity at a discount, and absorb the loss just as though it had bid an above-maximum rate for a shorter term.

The Commission acknowledged the reality that contract duration is a measure of value when it declared that its policy was "for the capacity to go to the person who values it the most, as evidenced by its willingness to bid the highest price for the longest reasonable time." Order No. 636-A, ¶ 30,950, at 30,630. As a general matter, in a perfectly competitive market, a long-term contract incorporates a premium for stability, and a pipeline naturally values a longer-term transportation contract more highly, ceteris paribus. Order No. 636, ¶ 30,939, at 30,450. Thus, the contract term-matching condition is a rational means of emulating a competitive market for allocating firm-transportation capacity. There are obvious drawbacks — the industrial petitioners provide the example of a factory owner with a productive asset that has only a short useful life. Order No. 636-A, ¶ 30,950, at 30,629-30. But industrial end-users are also far more likely to have ready access to alternative fuels than do the residential consumers served by LDCs. *See AGD I*, 824 F.2d at 995.

For purposes of pre-granted abandonment, however, the issue is whether the Commission has shown that its choice of a twenty-year term-matching cap protects consumers against the exercise of pipeline market power. The petitioners note that longer-term contracts lock in customers and serve as a barrier to entry into the pipeline market by potential competitors. Rival pipelines will not build extensions to their system if the market for additional capacity has been foreclosed by long-term contracts with the existing pipeline. The Commission responds only that the pipeline plays no role in the competitive bidding process and thus cannot exercise market power. In the Commission's view, its choice of a twenty-year period reflects a reasonable weighing of the relative interests in preventing market constraint and encouraging market stability. None of these explanations, however, supports a finding that the twenty-year term-matching cap adequately protects against pipelines' pre-existing market power, which they enjoy by virtue of natural-monopoly conditions. The Commission has not explained why the twenty- year cap will prevent bidders on capacity-constrained pipelines from using long contract duration as a price surrogate to bid beyond the maximum approved rate, to the detriment of captive customers. If the maximum approved rate artificially limits a rival shipper's ability to outbid the existing shipper, the rival shipper may offer a higher-value contract by bidding up the contract duration instead.[44]

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44. The LDC petitioners also contend that the Commission failed to consider that, following Order No. 636, LDCs are placed in a more vulnerable market situation, in which their traditional customers can purchase gas from marketers. The Commission reasonably responded that LDCs are no different from other industry participants in that they will have to evaluate future risks in determining how much capacity to reserve. Order No. 636-B, ¶ 61,272, at 62,026.

A further concern with the Commission's choice of a twenty-year cap is the Commission's reasoning in selecting twenty years. Most of the commentators before the agency had proposed much shorter contract-term caps, such as five years.[45] The Commission relied on the fact that twenty-year contracts have been "traditional" in the natural-gas industry. Order No. 636-A, ¶ 30,950, at 30,631 n.437. However, numerous commentators on rehearing of Order No. 636-A, as well as Commissioner Moler, *id.* at 30,679, pointed out that twenty-year contracts have been traditional only for contracts involving the construction of new facilities, where the pipeline requires a long-term contract to secure financing for the project, but not for contracts for the continuation of service after contract expiration. Indeed, both of the decisions that the Commission cited for the proposition that twenty-year contracts are customary were for new facilities.[46] Also, renewal contracts appear more similar to the situation in the right-of-first- refusal mechanism. The Commission in its brief responds that the term-matching cap was designed "not to determine the length of typical gas contracts, but to establish a reasonable outer boundary for contract length, within which the ROFR might reasonably

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45. The petitioners contend in part that the twenty-year cap cannot stand because the Commission failed to explain why it rejected the commentators' proposals for a shorter period. When, as here, the Commission must select some, necessarily somewhat arbitrary figure, we will defer to the Commission's expertise if it provides substantial evidence to support its choice and responds to substantial criticisms of that figure.

46. *See Pacific Gas Transmission Co.*, 56 F.E.R.C. ¶ 61,192, at 61,727-28, *order on reh'g*, 57 F.E.R.C. ¶ 61,097 (1991), *order on reh'g*, 62 F.E.R.C. ¶ 61,243 (1993), *petitions for review pending sub nom. Altamont Gas Transmission Co. v. FERC*, No. 91-1369 (D.C.Cir. argued Nov. 14, 1995); *Iroquois Gas Transmission Sys., L.P.*, 53 F.E.R.C. ¶ 61,194, at 61,779-82, 1990 WL 488925 (1990), *order on reh'g*, 54 F.E.R.C. ¶ 61,103 (1991).

function." The petitioners' claim, however, is that because the Commission looked to the wrong type of contract to determine the typical contract length it may have selected an outer boundary that is longer than it would have been if the Commission had examined the duration of renewal contracts. The Commission failed to respond to this objection in the Order No. 636 series.

Both of these reasons — the Commission's failure to explain why the twenty-year cap will protect against pipelines' market power, and the failure to explain why it looked at new-construction contracts in arriving at the twenty-year figure — persuade us to remand the length of the contract term-matching condition to the Commission for further consideration.[47] The right-of-first-refusal mechanism, incorporating the twin matching conditions of rate and contract term, is sufficiently justified. We remand only as to the Commission's reasons for adopting a twenty-year cap.

3. *Requirement to discount*

Petitioner Meridian Oil Inc., joined by the American Public Gas Association, challenges a different aspect of the right-of-first-refusal mechanism. The Commission declared that a

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47. The industrial petitioners also contend that the twenty-year cap is unduly discriminatory under § 5 of the NGA because industrial end-users are more likely to have shorter-term natural gas needs than other customers, such as LDCs who can count on still having residential customers twenty years in the future. The Commission responded that "[t]he requirement is not unduly discriminatory" because "[a]ll parties have an equal opportunity to bid for the capacity." Order No. 636-A, ¶ 30,950, at 30,632. Although the twenty-year cap may affect different classes of customers differently, under these circumstances it does not violate § 5.

pipeline need not accept a competing bid for a rate less than the maximum approved rate; in other words, "pipelines are not required to discount under the rule." Order No. 636-A, ¶ 30,950, at 30,629. The result is that a pipeline can choose between providing service to the highest bidder at a discounted rate and not providing service at all unless a shipper is willing to pay the maximum approved rate. In its comments to the Commission, Meridian urged that pipelines be required to accept the "best bid," which on pipelines on which capacity was not constrained would likely be less than the maximum approved rate. The Commission responded that it would

> not require pipelines to discount transportation rates. However, if a pipeline fails to attempt to maximize throughput, there is no guarantee that it will be able to recover all the costs of its underutilized capacity from its firm customers when it files its next rate case. Evidence that a pipeline refused to accept the highest valued bid for capacity below the maximum rate will be given significant weight during its next rate case.

Order No. 636-B, ¶ 61,272, at 62,028 (footnote omitted).

Meridian contends first that the Commission violated § 7(b) by discount. In Meridian's view, by forcing the existing customer to pay the maximum approved rate to ensure continuity of service, even if the competitive outcome as determined by the bidding process is a below-maximum rate, the Commission has failed to protect customers against pipelines' market power. *See Mobil Oil*, 498 U.S. at 227, 111 S.Ct. at 625; *AGA II*, 912 F.2d at 1517. However, as we held above, the Commission has already

protected against pipelines' market power by removing the pipeline's ability to influence the bidding and by limiting the maximum rate that the pipeline may charge. *See* supra at 76. The Commission first authorized selective discounting by pipelines providing transportation under a Part 284 blanket certificate in Order No. 436, ¶ 30,665, at 31,540-48. *See* 18 C.F.R. § 284.7(d)(5); *AGD I*, 824 F.2d at 1007-13; *see also Mississippi Valley Gas Co.*, 68 F.3d at 507. Given that the purpose of selective discounting is to increase throughput by allowing pipelines to engage in price discrimination in favor of demand-elastic customers, *AGD I*, 824 F.2d at 1011, Meridian's proposal that pipelines be required to discount in favor of demand-inelastic, captive customers would render meaningless pipelines' ability to charge up to the maximum approved rate. The § 7(b) abandonment provisions protect customers against loss of service only if the customer is willing to pay the maximum rate approved in a rate proceeding.

Meridian's second contention is that the Commission acted in an arbitrary and capricious manner by not responding to Meridian's comments that the lack of a requirement to discount would prevent the right-of-first-refusal mechanism from reflecting competitive market forces on pipelines with excess capacity. The Commission responded to Meridian's objection by assuring that a pipeline is not entitled to full cost recovery in its next rate proceeding when it forgoes the opportunity to recover some of its fixed costs from a bid rate between the minimum and maximum filed rates.[48] Order No. 636-B, ¶ 61,272,

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48. Because we are satisfied by the Commission's assurance that it will examine pipelines' failure to discount in rate proceedings, we need not address the Commission's alternative contention in its brief that requiring pipelines to discount would violate the Commission's duty to ensure adequate capitalization to pipelines.

at 62,028. Meridian has offered no reason why the Commission's rate scrutiny will not provide sufficient incentives for pipelines to discount in appropriate circumstances. Accordingly, we affirm the Commission's decision not to require pipelines to discount in the right-of-first-refusal process.

C. *Curtailment*

When supply shortages arose in the natural gas industry during the 1970s, the Commission adopted end-use curtailment plans to protect high-priority customers from an interruption of supply. *See generally Consolidated Edison Co. v. FERC*, 676 F.2d 763, 765-67 (D.C.Cir.1982); *North Carolina v. FERC*, 584 F.2d 1003, 1006-08 (D.C.Cir.1978). In 1973, the Commission found itself " 'impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation of this wasting resource.' " Order No. 467, 49 F.P.C. 85, 86 (quoting *Arkansas Louisiana Gas Co.*, 49 F.P.C. 53, 66 (1973)), *order on reh'g*, 49 F.P.C. 217, *order on reh'g*, 49 F.P.C. 583 (1973), *petitions for review dismissed sub nom. Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33 (D.C.Cir.1974). The Commission's end-use curtailment schemes were essentially enacted into law by title IV of the Natural Gas Policy Act of 1978 (NGPA),[49] which establishes the following priority system:

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49. Section 401(a) provides that:

> "[T]he Secretary of Energy shall prescribe and make effective a rule, . . . which provides that, . . . to the maximum extent practicable, no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any essential

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> Whenever there is an insufficient supply, under the Act first in line to receive gas are schools, small business, residences, hospitals, and all others for whom a curtailment of natural gas could endanger life, health, or the maintenance of physical property. After these "high-priority" users have been satisfied, next in line are those who will put the gas to "essential agricultural uses," followed by those who will use the gas for "essential industrial process or feedstock uses," followed by everyone else.

Process Gas Consumers Group v. United States Dep't of Agric., 657 F.2d 459, 460 (D.C.Cir.1981) (*Process Gas I*); *see also* 18 C.F.R. §§ 281.201-281.215 (the Commission's regulations implementing NGPA § 401).

With the introduction of stand-alone firm-transportation service in Order No. 436, the Commission distinguished for the first time between supply curtailment and capacity curtailment. Transportation service can suffer from a capacity interruption (such as a force majeure loss of capacity due to pipeline system failure or a pipeline's overbooking of capacity), whereas sales service can suffer from a shortage in the supply of gas. *See* Order No. 436, ¶ 30,665, at 31,515; Order No. 436-A, ¶ 30,675, at

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> agricultural use, unless such curtailment . . . (2) is necessary in order to meet the requirements of high priority users."

15 U.S.C. § 3391(a); *see also id.* § 401(f)(2), 15 U.S.C. § 3391(f)(2) (defining "high-priority user").

31,652. The Commission's subsequent approach was to allow pipelines to adopt pro rata capacity curtailment (allocation proportional to the amount reserved, without regard to end use), *see, e.g., Texas Eastern Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,692-93, 1986 WL 215099 (1986), *order on reh'g*, 41 F.E.R.C. ¶ 61,015 (1987), *aff'd sub nom. Texaco, Inc. v. FERC*, 886 F.2d 749 (5th Cir.1989), unless the parties agreed to end-use capacity curtailment on a particular pipeline, *see, e.g., Florida Gas Transmission Co.*, 51 F.E.R.C. ¶ 61,309, at 62,010-11, *order on reh'g*, 53 F.E.R.C. ¶ 61,396 (1990).

In *City of Mesa v. FERC*, 993 F.2d 888 (D.C.Cir.1993), the court reviewed a proceeding in which the Commission had approved end-use curtailment for supply shortages but pro rata curtailment for capacity interruption. *El Paso Natural Gas Co.*, 54 F.E.R.C. ¶ 61,316, at 61,928-29, order on reh'g, 56 F.E.R.C. ¶ 61,290, at 62,153-54 (1991). First, the court upheld the Commission's interpretation of the word "deliveries" in § 401(a) of the NGPA to refer only to pipelines' sale of gas, so that the statutory end-use curtailment scheme in title IV applied only to supply curtailment. 993 F.2d at 892-94; *see also Atlanta Gas Light Co. v. FERC*, 756 F.2d 191, 196-97 (D.C.Cir.1985). The court found that different treatment of supply and capacity curtailment was reasonable because high-priority users can "generally 'fend for themselves' " to protect against capacity interruption:

> Supply shortages usually lead to prolonged periods in which there is simply too little gas to serve the needs of all users. In contrast, capacity constraints occur when there is enough gas in the market but an unexpected event has caused a brief interruption in the

> movement of the gas to consumers. Additionally, capacity constraints, unlike supply shortages, may only affect the movement of gas on part of a pipeline, thereby allowing customers to receive their quota of gas by using alternate routes that skirt the pipeline bottleneck. These differences mean that pipeline customers can more easily adopt self-help measures to protect their high-priority end-users against the harmful effects of capacity curtailments than supply shortages.

City of Mesa, 993 F.2d at 894-95.

Although City of Mesa upheld the limitation of title IV of the NGPA to supply shortages, the court acknowledged that the NGA provided protections for capacity shortages. The court stated that "implicit in th[e] consumer protection mandate [of NGA §§ 4 and 7(e)] is a duty to assure that consumers, especially high-priority consumers, have continuous access to needed supplies of natural gas." 993 F.2d at 895. This duty arises because " '[n]o single factor in the Commission's duty to protect the public can be more important to the public than the continuity of service provided.' " *Id.* (quoting *Sunray Mid-Continent Oil Co. v. FPC*, 239 F.2d 97, 101 (10th Cir.1956), *rev'd on other grounds*, 353 U.S. 944, 77 S.Ct. 792, 1 L.Ed.2d 794 (1957)). The court emphasized that "since the NGA gives the FERC no specific guidance as to how to apply its broad mandates in a particular case, our review of the FERC's actions here is, again, quite limited." *Id.* In *City of Mesa*, the court concluded that the Commission had failed to engage in reasoned decision making when it approved a curtailment plan that protected "most" high-

priority users rather than all such users. *Id.* at 896-97. The court noted that in Order No. 636-A the Commission had held that "self-help strategies were generally sufficient to assure protection of end-users and thus to meet NGA mandates" but did not further examine whether self-help measures were adequate to protect against capacity curtailment. *Id.* at 897.

In Order No. 636, which was issued before the court's decision in City of Mesa, the Commission continued without change its curtailment policies since Order No. 436. First, the Commission acknowledged that, as a policy matter, it chafed at the title IV end-use curtailment scheme for supply shortages but stated that it was bound by the statute. Order No. 636, ¶ 30,939, at 30,430; *see also Transcontinental Gas Pipe Line Corp.*, 57 F.E.R.C. ¶ 61,345, at 62,117 (1991). The Commission reiterated its reading of § 401(a) that limited its scope to pipelines' sale of gas. Order No. 636- A, ¶ 30,950, at 30,586-89. Second, the Commission maintained that self-help measures would allow the consumer-protection mandate of the NGA to be satisfied by pro rata capacity curtailment:

> The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's [sic] and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers,

> storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (e.g., local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options.

Id. at 30,590.

The Commission's curtailment policies are challenged from both sides. Elizabethtown Gas Company contends that the Commission should have adopted pro rata curtailment for shortages in the supply of pipeline gas, and a group of small distributors contends that the Commission should have adopted end-use curtailment for capacity interruption and for shortages in the supply of third- party gas.

1. *Supply curtailment of pipeline gas*

Elizabethtown contends that because § 402(a) of the NGPA requires end-use curtailment only "to the maximum extent practicable," 15 U.S.C. § 3392(a), the declining role of pipelines as gas merchants renders end-use curtailment for shortages of pipeline gas no longer "practicable." The court recently rejected this argument, made by the same petitioner, in *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866 (D.C.Cir.1993) (*Elizabethtown III*):

> This argument makes no sense to us. Even if [the pipeline] supplies a smaller share of the gas bought by each of the LDCs, the gas it does deliver to them could still in times of

> shortage go first to "high-priority users." Accordingly, it seems entirely "practicable" to increase the level of protection for high priority users above that provided by the pro rata plan.

Id. at 874; *see also Process Gas Consumers Group v. United States*, 694 F.2d 778, 787-92 (D.C.Cir.1982) (*en banc*) (*Process Gas II*) (holding that the phrase "to the maximum extent practicable" gives the Commission broad powers). Although Elizabethtown contends that the near- elimination of pipelines as gas merchants following Order No. 636 requires us to reconsider our holding in Elizabethtown III, this change in the industry does not affect our reasoning that end-use curtailment remains "practicable" no matter how small the pipelines' share of the gas-sales market. The Commission recognized that the limitation of title IV of the NGPA to pipelines' sale of gas means that pipelines are disadvantaged vis-a-vis other gas merchants, but explained that it remained bound by the statute. Order No. 636, ¶ 30,929, at 30,430. Because we have already decided this question in Elizabethtown III, we affirm the Commission's decision that title IV of the NGPA mandates end-use curtailment for shortages in the supply of pipeline gas.

Elizabethtown also maintains that the Commission acted arbitrarily in not requiring high-priority users to compensate pipeline customers who lose gas supply under end-use curtailment. In Elizabethtown III, the court "held that a compensation provision is not necessarily inconsistent with § 401(a)." 10 F.3d at 875. Indeed, this court has long held that the Commission retains the authority under title IV of the NGPA to adopt a compensation scheme. *See Consolidated Edison Co. v. FERC*, 676 F.2d 763, 767 (D.C.Cir.1982); *cf. Elizabethtown*

Gas Co. v. FERC, 575 F.2d 885, 887-89 (D.C.Cir.1978) (*Elizabethtown I*) (holding that the Commission has authority under the NGA to adopt a curtailment compensation plan). In *Elizabethtown III*, the court remanded with instructions for the Commission to consider Elizabethtown's "request for a curtailment compensation scheme." *Id.* In the Order No. 636 series, decided before the court's decision in Elizabethtown III, the Commission stated that its

> position on curtailment compensation plans is that the parties in the individual restructuring proceedings must explore the development of such schemes . . . in the context of developing their individual curtailment plans and in the development of voluntary emergency contractual arrangements between shippers. However, the Commission believes that it would be contrary to the concept of the restructuring proceeding process and the negotiation and development of individually tailored curtailment allocation procedures and emergency mechanisms for it to mandate a generic compensation scheme.

Order No. 636-A, ¶ 30,950, at 30,592; *see also* Order No. 636, ¶ 30,929, at 30,430. The comments by the Commission in the Order No. 636 series continue the Commission's pattern of avoiding the question of curtailment compensation and do not exhibit the reasoned consideration of curtailment compensation that the court subsequently requested in Elizabethtown III.

The Commission has reconsidered the issue of curtailment

compensation, however, on remand from Elizabethtown III. *See Transcontinental Pipe Line Corp.*, 72 F.E.R.C. ¶ 61,037, reh'g denied, 73 F.E.R.C. ¶ 61,357 (1995). In those proceedings, the Commission

> conclude[d] that compensation is needed to render Transco's gas supply curtailment plan just and reasonable. The priority curtailment plan affects the contractual rights of Transco's customers by altering the pro rata allocation of curtailed supplies so that higher priority customers can obtain gas that would otherwise go to lower priority customers.

72 F.E.R.C. ¶ 61,037, at 61,235. The Commission rejected Elizabethtown's proposed compensation scheme, however, in favor of requiring the higher-priority customer to pay: (1) 150% of the spot market price for gas if the lower-priority customer was unable to cover (locate replacement gas on the spot market), or (2) the difference between the cover price and the original contract price if the lower-priority customer was able to cover. *Id.* at 61,237-38.

In light of the Commission's *Transcontinental* decision, the issue of curtailment compensation is not ripe for review. The Commission enjoys broad discretion whether to adopt a compensation scheme on a generic basis or in pipeline-specific proceedings. *See Mobil Oil*, 498 U.S. at 230, 111 S.Ct. at 627. If Elizabethtown remains aggrieved by the Commission's decision to accept its general argument but fashion a different compensation mechanism, then it may seek relief in review of the *Transcontinental* decision. We therefore express no opinion on the appropriateness of any particular curtailment compensation plan.

2. *Capacity curtailment*

The small distributor petitioner group, on the other hand, contends that pro rata capacity curtailment violates the consumer-protection mandate of the NGA. We review the Commission's policy on pro rata curtailment to determine whether it is "just and reasonable" under § 4 and whether it serves the "present or future public convenience and necessity" under § 7(e). *See City of Mesa*, 993 F.2d at 895. The Commission decided that the consumer-protection mandate of the NGA did not require it to adopt end-use capacity curtailment across the board and promised to address the issue in each pipeline restructuring proceeding. Order No. 636-A, ¶ 30,950, at 30,591-92. Indeed, the Commission has broad latitude on whether to effectuate its policies in generic rulemakings or in individual-pipeline adjudications. *Mobil Oil*, 498 U.S. at 230, 111 S.Ct. at 627. The issue presented to us, then, is whether the Commission's decision that the NGA does not require end-use curtailment in all circumstances is " 'reasoned, principled, and based upon the record.' " *Great Lakes Gas Transmission Ltd. Partnership v. FERC*, 984 F.2d 426, 432 (D.C.Cir.1993) (quoting *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578, 593 (D.C.Cir.1979)).

The Commission explained that Order No. 636 had allowed the development of market structures that would enable customers to take independent, market-based steps to avoid the need for Commission-mandated end-use curtailment. Order No. 636-A, ¶ 30,950, at 30,590. Moreover, the Commission found that since the enactment of the NGPA in 1978 "the industry has not experienced shortages beyond isolated, short-lived dislocation," *id.* at 30,591, and "gas has always flowed according to the dictate of the market, *i.e.*, to the heat sensitive users who

need it most and who are thus willing to pay the prevailing market price for it." *Id.* at 30,592. This experience with the industry provides substantial evidence for the Commission's conclusion that end-use curtailment is not required in all circumstances.

We are unpersuaded, particularly in light of the Commission's own actions in the restructuring proceedings, that pro rata capacity curtailment would adequately protect all high-priority customers on all pipelines. *Cf. City of Mesa*, 993 F.2d at 896-97. The Commission's market-based alternatives for customers to avoid curtailment fall into the following categories: (1) arrangements with other pipelines; (2) arrangements with other gas sellers; (3) arrangements for gas storage; (4) arrangements with other customers (including the capacity-release mechanism); and (5) "peak shaving."[50] First, arrangements with other pipelines are more widely available after Order No. 636, such as by using different pipelines that connect to one "market center," but a capacity constraint on a pipeline will still cut off delivery to any "captive customers," no matter how many transportation options some other customers may have. Second, arrangements with other gas sellers are by definition relevant only to supply curtailment, not to capacity curtailment. Third, arrangements for gas storage are unhelpful if the capacity interruption occurs at a point between the contract-storage area and the customer's receipt point. Fourth, obtaining gas from other customers, whether through the capacity-release mechanism or otherwise, depends upon the willingness of lower-priority customers to forgo deliveries. Fifth, practices such as "peak shaving" (letting a little gas go a longer

50. Peak shaving is "the practice of adding propane air mixtures to augment supplies of natural gas during periods of peak demand." *Atlanta Gas Light*, 756 F.2d at 195 n. 5.

way) can temporarily help to alleviate curtailment problems but cannot ensure continuous service if the interruption lasts too long. None of these market-based solutions, therefore, can guarantee continuous service to all high-priority customers in cases of capacity interruptions. Many of the market-based solutions fail to acknowledge that many customers have far less control over access to pipeline capacity than they do over gas supply. In addition, some of the self-help mechanisms will be more readily available to larger pipeline customers. *City of Mesa*, 993 F.2d at 897 n. 7.

Yet the Commission has not applied Order No. 636 in the restructuring proceedings to preclude the development of curtailment plans that provide more protection to higher-priority users. For example, on remand from *City of Mesa*, the Commission reiterated its general policy that "customers can, and should, avail themselves of self-help methods to obtain their needed supplies" but, in light of the decision in *City of Mesa*, ordered El Paso to "includ[e] provisions giving relief to any high priority shipper when that shipper has exercised all other self-help remedies in times of bona fide emergencies." *El Paso Natural Gas Co.*, 69 F.E.R.C. ¶ 61,164, at 61,624 (1994), *order on reh'g*, 72 F.E.R.C. ¶ 61,042, *reh'g denied*, 73 F.E.R.C. ¶ 61,074 (1995). In another restructuring proceeding, the Commission approved a settlement and found its curtailment plan consistent with *City of Mesa* because it "provides an exemption from pro rata curtailment whenever necessary to avoid irreparable injury to life or property." *Florida Gas Transmission Co.*, 70 F.E.R.C. ¶ 61,017, at 61,061 (1995). On occasions, the Commission has suggested that "there may be extraordinary circumstances when reasonable self-help efforts are insufficient, even for large customers," such that some emergency protections may always be required for certain force

majeure capacity interruptions. *El Paso*, 69 F.E.R.C. ¶ 61,164, at 61,624; *see also United Gas Pipe Line Co.*, 65 F.E.R.C. ¶ 61,006, at 61,092, *reh'g denied sub nom. Koch Gateway Pipeline Co.*, 65 F.E.R.C. ¶ 61,338, at 62,630-31 (1993).

We need not reach the issue whether the adoption of a pure pro rata capacity-curtailment scheme on a generic basis would comply with the Commission's duty under the NGA to ensure that "high-priority consumers[ ] have continuous access to needed supplies of natural gas." *City of Mesa*, 993 F.2d at 895. All the Commission did in Order No. 636 was to decide not to require end-use capacity curtailment for all pipelines. Because the Commission expressly declared that it would re-examine the suitability of pure pro rata capacity curtailment for customers on each pipeline, Order No. 636-A, ¶ 30,950, at 30,591-92, we construe any indications that pro rata curtailment will be the default as unreviewable policy statements under § 4(b)(A) of the Administrative Procedure Act, 5 U.S.C. § 553(b)(A). *See Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33, 39 (D.C.Cir.1974). The manner in which the Commission has applied its curtailment policy in the restructuring proceedings supports our conclusion that any preference for pro rata schemes is not suitable for review. *See Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682-83 (D.C.Cir.1991). Accordingly, the compliance of specific curtailment plans with the NGA's consumer-protection mandate remains open on review of the restructuring proceedings.

We uphold the Commission's decision not to require end-use curtailment on a generic basis for capacity curtailment but to proceed instead on a case-by-case basis.

3. *Supply curtailment of third-party gas*

Finally, the small distributor petitioners contend that the consumer-protection mandate of the NGA requires the Commission to adopt end-use curtailment for shortages in the supply of third-party gas. The petitioners concede that title IV of the NGPA applies only to pipelines' sale of gas, but urge that §§ 4 and 7(e) of the NGA require some form of end-use curtailment for the sale of gas by producers and other third parties. The Commission declined to "impos[e] . . . the industry-wide, end-use supply curtailment scheme envisioned by the petitioners" because "the best protection against, and remedy for, supply shortages [i]s to allow the market to establish the price for gas." Order No. 636-A, ¶ 30,950, at 30,591.

As an initial matter, a group of intervenors in support of the Commission maintains that the Commission lacks jurisdiction under § 1(b) to enact a curtailment plan for third-party gas. But the Supreme Court has held expressly that "curtailment plans are aspects of [the Commission's] 'transportation' and not its 'sales' jurisdiction." *Louisiana Power & Light*, 406 U.S. at 641, 92 S.Ct. at 1839 (citing *Panhandle Eastern Pipe Line Co. v. Public Serv. Comm'n*, 332 U.S. 507, 523, 68 S.Ct. 190, 198, 92 L.Ed. 128 (1947)). The intervenors rely on a Fifth Circuit case, *Sebring Utilities Commission v. FERC*, 591 F.2d 1003 (5th Cir.), *cert. denied*, 444 U.S. 879, 100 S.Ct. 167, 62 L.Ed.2d 109 (1979), in which the court indicated that the Commission would not have jurisdiction to order curtailment of gas not owned by a statutory "natural-gas company." *Id.* at 1016-19. However, the ownership of the gas is not relevant to the Commission's transportation jurisdiction because in adopting a curtailment scheme the Commission exercises its jurisdiction over the pipeline, which incorporates

any curtailment plan into its tariff.[51] If we were to follow *Sebring*, then the Commission would also lack jurisdiction to regulate capacity curtailment of third-party gas — a proposition implicitly rejected by the *City of Mesa* court, which in remanding on the capacity-curtailment issue assumed that the Commission had jurisdiction over curtailment plans for third-party gas. 993 F.2d at 895-98. Moreover, *Sebring* was decided before the unbundling of sales from transportation, at a time when virtually all gas was pipeline-owned.[52] Under the principles of Louisiana Power & Light, the Commission's transportation jurisdiction extends to supply curtailment of third-party gas.

The Commission decided that an end-use supply curtailment plan for third-party gas was not required to ensure high-priority customers "continuous access to needed supplies of natural gas." *City of Mesa*, 993 F.2d at 895. As discussed with respect to capacity curtailment, *see supra* at 83-84, the Commission

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51. Our reasons for holding that the Commission may apply a curtailment plan to shortages in the supply of gas owned by someone not a "natural-gas company" are the same as our reasons, for holding that the Commission may apply a capacity-release plan to capacity rights held by a municipal LDC, which is not a "natural-gas company." *See infra* Part III.B.3.

52. The intervenors also rely on *American Public Gas Association v. FERC*, 587 F.2d 1089 (D.C.Cir.1978) (per curiam), in which the court approved the Commission's policy at that time of excluding "direct sales" gas (gas sold directly from producers to LDCs or certain high-priority end-users) from pipelines' end-use curtailment plans, so as to alleviate the shortage of gas in the interstate market. *Id.* at 1097-98. Nothing in that opinion, however, limits the Commission's § 1(b) transportation jurisdiction to pipeline-owned gas or precludes the Commission from adopting a different policy for the curtailment of third-party gas, given the changed circumstances in the end of the gas shortage and the unbundling of sales and transportation. *See* Order No. 636-A, ¶ 30,950, at 30,589-90.

provided a list of market-based alternatives to secure the continuous supply of gas that is convincing in the context of supply curtailment. Although the petitioners posit a force majeure supply shortage that the market-based protections would not cover, namely a "freeze-off" of wells that would prevent all producers from producing sufficient quantities of gas during cold weather, the petitioners have provided no evidence that such an event has ever occurred or is likely to occur in the future. The Commission's decision that such an occurrence is unlikely "given foreseeable supply conditions" is reasonable. Order No. 636-A, ¶ 30,950, at 30,591. In addition, the Commission noted that title III of the NGPA, 15 U.S.C. §§ 3361-3364, authorizes the President to "declare a natural gas supply emergency" in the event of "a severe natural gas shortage, endangering the supply of natural gas for high-priority uses." *Id.* § 3361(a); *see* Order No. 636-A, ¶ 30,950, at 30,591.

Thus, the Commission has complied with the continuity-of-service guarantee of the NGA, as articulated in *City of Mesa*, with respect to supply shortages of third-party gas.

III. Capacity Release

In this part of the opinion, we address challenges to the voluntary capacity release provisions of Order No. 636, which permit holders of firm transportation rights on a gas pipeline to resell them. 18 C.F.R. § 284.243 (1995).[53] Petitioners challenge the Commission's jurisdiction to institute its capacity release program generally, as well as its jurisdiction over (1) LDCs' capacity sales to their local end-users; (2) capacity sales by municipal LDCs; and (3) state-regulated "buy/sell" transactions.

53. Our review is confined to the the capacity release provisions before they were amended by Order No. 577. *See supra* at 64 n. 18.

Petitioners also challenge the exclusion of individually certificated shippers from the capacity release program, the standards that FERC promulgated for determining the prevailing bidder in the capacity release transaction, and the mechanism for crediting interruptible transportation revenues. We conclude that each of petitioners' claims is either incorrect on the merits or is not suited for review in these proceedings.

A. *Introduction*

Among the central goals of Order Nos. 436 and 636 has been the conversion of bundled sales arrangements into separate transportation and gas sales transactions. On the transportation side, the Commission recognized that while much of the nation's interstate pipeline capacity was reserved for firm transportation, those transportation rights ultimately were not being utilized. *See supra* Part I.C. FERC therefore sought to develop an active "secondary transportation market," with holders of unutilized firm capacity rights reselling them in competition with any capacity offered directly by the pipeline.[54] According to the Commission:

> Capacity reallocation will promote efficient load management by the pipeline and its customers and, therefore, efficient use of the pipeline capacity on a firm basis throughout the year. Because more buyers will be able to reach more sellers through firm transportation capacity, capacity reallocation comports with

54. In this sense, the Commission's description of capacity release as creating a secondary transportation market is somewhat misleading, given that both resales of firm capacity and initial sales by pipelines are in direct competition with each other, and unavailable in any other forum.

> the goal of improving nondiscriminatory, open-access transportation to maximize the benefits of the decontrol of natural gas at the wellhead and in the field.

Order No. 636, ¶ 30,939, at 30,418. Understanding petitioners' challenges to the capacity release program requires a brief review of related policies that the Commission has employed in the past to accomplish a similar end.

If a firm capacity holder does not ship gas under its transportation right, it pays the pipeline a "reservation fee," but does not pay a "usage fee." Historically, FERC prohibited such holders of unutilized firm capacity rights from transferring those rights to other shippers, and shippers were therefore able to purchase capacity rights only directly from pipelines. *See generally United Gas Pipe Line Co.*, 46 F.E.R.C. ¶ 61,060 (1989) (approving first experimental capacity brokering program). Beginning with the *Texas Eastern Transmission Corp.* proceedings, 48 F.E.R.C. ¶ 61,248, *order on reh'g*, 48 F.E.R.C. ¶ 61,378 (1989), *order on reh'g*, 51 F.E.R.C. ¶ 51,170, *order on reh'g*, 52 F.E.R.C. ¶ 61,273 (1990), however, the Commission authorized shippers on some pipelines to engage in nondiscriminatory "capacity brokering." Brokering arrangements allowed a holder of firm capacity rights (the "releasing shipper") to sell those rights to a "replacement shipper." The transaction took place directly between the two parties, and the replacement shipper essentially stepped into the shoes of the releasing shipper.

Three years later, in the Order No. 636 and companion *Algonquin Gas Transmission Corp.* proceedings, 59 F.E.R.C. ¶ 61,032 (1992), FERC concluded that it could not ensure that

the extant capacity brokering programs were operating in a nondiscriminatory manner. When transactions occurred directly and privately between shippers, there was no way to verify that certain purchasers were not being favored unreasonably over others. "Simply put, there [were] too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering. . . ." Order No. 636, ¶ 30,939, at 30,416. In FERC's view, fairness could be secured only if capacity resale transactions were both centralized on each pipeline and subject to open bidding. Moreover, uniformity among the various pipelines was necessary to "prevent any pipeline or firm shipper from achieving an undue advantage, or incurring an undue disadvantage, compared to firm shippers on other pipelines." *Id.*

Accordingly, in Order No. 636, the Commission instituted a uniform national "capacity release" program, and exercised its power under NGA § 5 to conform pipelines' existing capacity brokering certificates to that program.[55] *Id.* While both capacity brokering and capacity release arrangements involve the releasing shipper's decision to sell excess capacity, capacity release requires the central involvement of the pipeline in the transaction. Specifically, under capacity release, each interstate pipeline is required to establish and administer an electronic bulletin board ("EBB"), which is a computer through which putative releasing and replacement shippers may communicate.

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55. Capacity brokering agreements already in effect on the date that the pipeline implemented its capacity release program were not substantially altered by Order No. 636. Order No. 636, ¶ 30,939, at 30,421. The Order required that the pipeline enter into a contract directly with the replacement shipper, as it would under capacity release, with terms that mirrored those in the capacity brokering agreement. *Algonquin Gas Trans. Co.*, 59 F.E.R.C. ¶ 61,032, at 61,096-97.

Id. at 30,418. The EBB carries information about available and consummated capacity release transactions. For example, holders of excess firm capacity rights may "post" their available capacity on the EBB. Further, they may establish nondiscriminatory conditions on the sale, including a minimum price and any terms under which the release may continue.[56] Pipelines are also required to post on the EBB any firm capacity that they have available for sale, where the capacity competes for buyers against capacity made available for resale by shippers. "Potential purchasers of capacity will then be able to choose from among the pipeline and the releasers the service that best suits their needs." *Id.* at 30,419. In addition, shippers that wish to acquire firm capacity rights may post offers to purchase capacity on the EBB. 18 C.F.R. § 284.243(d); Order No.636-A, ¶ 30,950, at 30,565.

With two exceptions, the pipeline must sell the capacity to the highest bidder. First, "short-term transactions," *i.e.*, those for capacity releases of less than one month,[57] may be arranged between shippers without competitive bidding.[58] 18 C.F.R. § 284.243(h)(1); Order No. 636-A, ¶ 30,950, at 30,554. Second,

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56. For example, the releasing shipper may elect to release capacity only for so long as the temperature remains above a certain level. If the temperature were to drop, the firm capacity rights would revert to the releasing shipper. Order No. 636, ¶ 30,939, at 30,418.

57. FERC has amended the short-term transactions provision specifically to encompass those capacity releases of no more than 31 days. *See supra* at 64 n. 18. That amendment does not affect our review.

58. The transaction must still be posted on the EBB. In addition, extensions and roll-overs of "short-term" transactions are prohibited. 18 C.F.R. § 284.243(h)(2); Order No. 636, ¶ 30,939, at 30,551.

a releasing shipper may identify a replacement shipper on its own and enter into a "pre-arranged" deal. 18 C.F.R. § 284.243(b); Order No. 636, ¶ 30,939, at 30,418. In such a transaction, the selected replacement shipper need only match — rather than outbid — the highest offer made by any other shipper. 18 C.F.R. § 284.243(e). The net effect is that a shipper may ensure that it will receive certain capacity by entering into a pre-arranged deal that both conforms to the releasing shipper's conditions and matches the maximum allowable rate for the capacity. No matter what form the capacity release transaction takes, however, the purchase price for released capacity may not exceed the maximum rate set by FERC for the capacity. 18 C.F.R. § 284.243(e); Order No. 636, ¶ 30,939, at 30,420.

After the replacement shipper has been identified, the pipeline enters into a contract with it for firm capacity rights.[59] The pipeline then may elect to excuse completely the releasing shipper's obligation to pay the reservation fee and related costs. Order No. 636, ¶ 30,939, at 30,419. Otherwise, the releasing shipper is credited for those costs unless the replacement shipper defaults. 18 C.F.R. § 284.243(f); Order No. 636- A, ¶ 30,950, at 30,553. In no instance, however, is the releasing shipper liable for costs associated with the replacement shipper's transportation of gas.

We now turn to petitioners' varied challenges to the Commission's capacity release program.

B. *Jurisdictional Challenges*

Various petitioners challenge both FERC's jurisdiction to

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59. Order No. 636 pre-granted shippers a limited blanket certificate under NGA § 7 to release capacity in a nondiscriminatory manner.

institute a uniform capacity release program and its jurisdiction over specific transactions and entities. We begin, then, by outlining the Commission's jurisdiction under § 1(b) of the Natural Gas Act of 1938. Ultimately, we conclude that FERC's capacity release program is a legitimate exercise of its jurisdiction over the interstate transportation of natural gas.

In the early part of this century, state regulatory agencies actively involved themselves in structuring the natural gas industry. The Supreme Court, however, severely cabined those efforts in a series of decisions that interpreted the dormant Commerce Clause to preclude state regulation of both the interstate transportation of natural gas and its ensuing sale in wholesale markets.[60] Congress enacted the Natural Gas Act of 1938 to fill the resulting regulatory gap. The Act, as provided in § 1(b), applies

> [1] to the transportation of natural gas in interstate commerce, [2] to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and [3] to natural-gas companies engaged in such transportation or sale, but [does] not apply [4] to any other transportation or sale of natural gas or [5] to

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60. For an overview of the history of the Act's inception, *see generally Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377-80, 103 S.Ct. 1905, 1908-10, 76 L.Ed.2d 1 (1983); *Panhandle Pipe Line Co. v. Public Serv. Comm'n*, 332 U.S. 507, 514-21, 68 S.Ct. 190, 193-98, 92 L.Ed. 128 (1947); *Illinois Natural Gas Co. v. Central Ill. Pub. Serv. Co.*, 314 U.S. 498, 504-08, 62 S.Ct. 384, 386-88, 86 L.Ed. 371 (1942); *National Ass'n of Regulatory Util. Comm'rs v. FERC*, 823 F.2d 1377, 1382-87 (10th Cir.1987).

> the local distribution of natural gas or to the facilities used for such distribution or [6] to the production or gathering of natural gas.

15 U.S.C. § 717(b).

Petitioners' jurisdictional challenges require us to interpret the first and fifth provisions of § 1(b), which address the interstate transportation and "local distribution" of natural gas.[61] In truth, the two provisions are a unity. "It is well established that the ["local distribution"] proviso was added to the Act merely for clarification and was not intended to deprive [FERC] of any jurisdiction otherwise granted by § 1(b)." *Louisiana Power & Light*, 406 U.S. at 637 n. 14, 92 S.Ct. at 1837 n. 14; *see also East Ohio Gas*, 338 U.S. at 469-70, 70 S.Ct. at 269 ("[W]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among consumers within a particular local community, not the high-pressure pipe lines transporting the gas to the local mains."). As explained in the House Report on the Act:

> That part of the negative declaration that the act shall not apply to "the local distribution of natural gas" is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the

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61. For an overview of the Commission's transportation jurisdiction, *see generally Louisiana Power & Light*, 406 U.S. at 636-40, 92 S.Ct. at 1836-38; *United Gas Pipe Line Co. v. FPC*, 385 U.S. 83, 89, 87 S.Ct. 265, 269, 17 L.Ed.2d 181 (1966); *East Ohio Gas*, 338 U.S. at 467-74, 70 S.Ct. at 268-72; *Cascade Natural Gas Corp. v. FERC*, 955 F.2d 1412, 1415-21 (10th Cir.1992); *Michigan Consol. Gas Co. v. FERC*, 883 F.2d 117, 121-22 (D.C.Cir.1989).

> Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.

H.R.REP. NO. 709, 75th Cong., 1st Sess. 3 (1937). And, as this circuit has concluded:

> Insofar as congressional committees spoke to the matter, therefore, they appear to have viewed distribution as confined to its parceling out function and (probably) even more narrowly, to parceling out accompanied by retail sales. As § 1(b) gave the Commission jurisdiction only over sales for resale, the states had unquestioned authority over retail sales anyway, making the reservation for distribution surplusage.

Public Utils. Comm'n v. FERC, 900 F.2d 269, 276 (D.C.Cir.1990).

We now consider whether FERC has done more than its interstate transportation jurisdiction permits.

1. *FERC's jurisdiction to regulate capacity release*

Petitioners' first jurisdictional challenge is the claim of the LDCs that FERC lacks any authority whatsoever to regulate shippers' resale of firm capacity rights. "LDCs' capacity assignments," they maintain, "involve sales of LDCs' rights to transportation service but do not involve interstate transportation or sale for resale of gas itself." As we understand their position,

the LDCs would limit FERC's regulatory authority over transportation to the rendition of interstate gas transportation services, as opposed to authority over the rights to receive those services. As their theory goes, the Commission has jurisdiction over the pipelines' initial sales of transportation capacity — given that it is the pipelines that render transportation services — but is without jurisdiction over resales of those same capacity rights by third parties — given that those third parties do not render transportation services.

Initially, we believe that the distinction drawn by the LDCs between the "rights to" and "rendition of" interstate transportation services is not a meaningful one. While the pipeline provides transportation only when a party utilizes capacity rights to transport gas, the pipeline provides transportation services throughout the capacity release process. Specifically, the pipeline operates the electronic bulletin board on which all prospective transactions are posted and consummated. The pipeline also selects the winning bidder in the transaction. Moreover, unlike capacity brokering arrangements, which occur directly between releasing and replacement shippers, capacity release requires the pipeline to contract with the replacement shipper. "In effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper. Both of these activities are subject to the Commission's jurisdiction under NGA section[ ] 1(b). . . ." Order No. 636-A, ¶ 30,939, at 30,551. In sum, the capacity release regulations operate as a term or condition of pipeline service, with which its customers must comply.

As an entirely separate matter, the Commission's jurisdiction attaches to the subject of the capacity resale

transaction: interstate transportation rights. "By controlling such capacity, the assignors are effectively determining by whom, and under what circumstances, gas will be transported and are using the pipeline's facilities as if they were the assignors' facilities." *Id.* (quotation marks, alteration, and citation omitted). In contrast, under the regulatory system envisioned by the LDCs, holders of capacity rights could engage in resales without regard to the principles of open access and nondiscrimination that are at the heart of the uniform capacity release system. Such a result is directly contrary to Congress' intent in enacting the Natural Gas Act. Responding to the Supreme Court's conclusion that the Constitution's dormant Commerce Clause prohibited state regulation of the interstate transportation of natural gas, *see supra* at 88, the federal government interceded to ensure stability and protect the interests of the consuming public. It thereby occupied the field, which necessarily includes both the sale and resale of interstate transportation rights.

2. *Jurisdiction over LDCs' capacity sales to their own end-users*

Several petitioners make more limited claims that specific classes of entities and transactions must be exempted from the Commission's control over capacity resales. First, the PUCs and LDCs together argue that FERC lacks jurisdiction over capacity sales by LDCs to their own end-users. Such transactions, they maintain, fall within the NGA's "local distribution" exemption. Specifically, according to petitioners, the Commission has always recognized that the states have jurisdiction to regulate bundled sales of natural gas by LDCs to their end-users, which necessarily involves some indirect influence over the interstate transportation element of the sale. State authority remains intact for LDCs' rebundled sales of gas and transportation even after

the implementation of Order No. 636. They contend that there is no functional difference between that jurisdictional arrangement and state regulation of LDCs' sales of unbundled gas and — more relevant here — transportation to local end-users. In particular, petitioners contend that state regulatory commissions need the freedom to control LDCs' assignment of capacity so that local end-users will be ensured of access to pipeline service.

But, as we have already explained, petitioners' reading of NGA § 1(b)'s reference to "local distribution" is flawed; the proviso does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas. In this regard, we find the Commission's explanation of the regulatory environment far more convincing. States have been — and are still — permitted to regulate LDCs' bundled sales of natural gas to end-users because those transactions include transportation over local mains and the retail sale of gas. In contrast, states have never regulated the terms and conditions of interstate pipeline transportation. When the gas sales element is severed — i.e., unbundled — from the transaction, FERC retains jurisdiction over the interstate transportation component.[62]

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62. The LDCs briefly argue that NGA § 1(c), the so-called 'Hinshaw exemption,' deprives the Commission of jurisdiction over their capacity sales to their own end-users. In this regard, they refer us to Congress' determination in § 1(c) that certain pipelines are "matters primarily of local concern and subject to regulation by the several States." 15 U.S.C. § 717(c). For the reasons set out in the text, however, the Commission's authority to regulate capacity release arises from its jurisdiction over the interstate pipeline that consummates the transaction and the subject of the transaction, the interstate transportation of gas, entirely independent of its jurisdiction over the releasing or replacement shipper. Accordingly, we reject the LDCs' claim, given that they do not suggest that FERC has improperly exercised jurisdiction over the release of capacity held on nonjurisdictional Hinshaw pipelines.

3. *Jurisdiction over municipal capacity release*

We now turn to the claim of the municipally owned local distribution companies ("municipalities") that FERC does not have jurisdiction to require them to comply with its capacity release regulations. Petitioners parse the terms of the Natural Gas Act as follows:

> Municipalities are exempt from the Commission's jurisdiction under the NGA. The Commission's NGA jurisdiction extends only to "natural gas companies." A "natural gas company" is defined in NGA Section 2(6) as "a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." NGA Section 2(1) defines a "person" as an "individual" or a "corporation." NGA Section 2(2) defines a "corporation" as inter alia, any corporation, partnership or association, but the definition expressly excludes "municipalities."

Small Distributors' and Municipalities' Br. at 11-12 (footnotes omitted).

Of course, as discussed above, *see supra* Part III.B.1, NGA § 1(b) extends the Commission's jurisdiction over not only "natural-gas companies" but also the interstate transportation of natural gas. FERC, however, has twice rejected the suggestion that it should invoke its transportation jurisdiction over

municipalities.[63] *See Tennessee Gas Pipeline Co.*, 69 F.E.R.C. ¶ 61,239, at 61,906-07 (1994), *reh'g denied*, 70 F.E.R.C. ¶ 61,329 (1995); *Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170, at 61,453-54 (1990). Accordingly, FERC wholly "agrees with [petitioners] that municipalities are beyond [its] jurisdiction." Order No. 636-A, ¶ 30,950, at 30,551.[64]

That notwithstanding, FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations. As we explained above, *see supra* Part III.B.1, FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas pipelines.[65] The pipelines' role in capacity release is absolutely

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63. Our opinion should not be read to either approve or disapprove the Commission's reading of the Natural Gas Act in this regard.

64. *Accord Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170 (1990) ("The Philadelphia Gas Works requests clarification that all the conditions imposed upon [capacity brokering] program participants do not apply to municipalities. Since municipalities are beyond the jurisdiction of this Commission, the Philadelphia Gas Works is correct."); *Northwest Alabama Gas District*, 42 F.E.R.C. ¶ 61,371, at 62,086, 1988 WL 391438 (1988) ("It is well settled that we cannot regulate a municipality under the NGA or the NGPA."); *Panhandle Eastern Pipe Line Co. v. City of Rolla*, 26 F.P.C. 736, 738 (1961) ("From [the plain language of the Natural Gas Act] it is clear that municipalities cannot be 'natural-gas companies' as that term is used by the Act. We are not, therefore, vested with jurisdiction to regulate municipalities, even though they are engaged in the sale of natural gas to interstate pipeline companies.").

65. Thus, in instituting the capacity release program, the Commission legitimately invoked its authority under NGA § 5 over "any rate, charge, or classification" or "any natural-gas company," 15 U.S.C. § 717d, given that pipelines are natural-gas companies under the Act.

central,[66] and the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers.[67]

The analogy drawn by the Commission, and the one we find most persuasive, is to the pipeline curtailment regime. As explained in Judge Rogers' opinion for the court, *see supra* Part II.C, pipelines at times must interrupt and redistribute their service based on shortages of both gas supply and pipeline capacity. The Supreme Court has expressly approved the Commission's authority to regulate such curtailments pursuant to its § 1(b) interstate transportation jurisdiction. *See Louisiana Power & Light Co.*, 406 U.S. at 640-41, 92 S.Ct. at 1838-39. The Commission's capacity release program is strikingly similar to its curtailment regulations, in that both involve the pipelines' allocation of transportation capacity among their shippers in compliance with federally mandated strictures. As the municipalities are subject to the curtailment regulations, so too must they comply with FERC's standards for capacity release.

We also find compelling the acknowledged jurisdictional arrangement prior to the implementation of either capacity

66. That factor distinguishes this case from the *Texas Eastern* proceedings, 51 F.E.R.C. ¶ 61,170 (1990), in which FERC concluded that it lacked jurisdiction to require municipal LDCs to comply with its capacity brokering standards.

67. The municipalities contend that the pipelines' involvement in capacity release is too ministerial to establish the Commission's jurisdiction. While we ultimately disagree with that argument for the reasons set forth in the text, we recognize its relevance. This could well be a different case had FERC in fact merely manipulated its regulations to involve the pipelines in a minimal way only to thereby create a jurisdictional toehold over a nonjurisdictional entity.

brokering or capacity release. At that time, shippers acquired firm capacity rights directly from pipelines on a first-come, first-served basis. Resales of capacity by shippers, including municipalities, simply did not occur. We therefore conclude that the Commission has jurisdiction to require open, nondiscriminatory capacity release by municipalities.

4. *Jurisdiction over "buy/sell" arrangements*

The final jurisdictional challenge to the capacity release mechanism involves "buy/sell" transactions, which FERC professed to bar[68] in Order No. 636 and the companion El Paso Natural Gas Co. proceedings, 59 F.E.R.C. ¶ 61,031, *reh'g denied*, 60 F.E.R.C. ¶ 61,117 (1992). "Buy/sells" occur in three stages. First, an end-user of gas either purchases or identifies certain natural gas at the point of production. The LDC that services the end-user then purchases the gas and transports it first under its own transportation rights on an interstate pipeline and later across its local distribution facilities.[69] The end-user then receives the gas from the LDC. The "buy/sells" reviewed by the

68. Buy/sell" agreements in place before the date that Order No. 636 went into effect were allowed to continue in force, but were required to be posted on the pipeline's electronic bulletin board for informational purposes. Order No. 636, ¶ 30,939, at 30,416-17.

69. Hadson Gas Co. contends that FERC has yet to make clear the precise nature of the transactions that it has prohibited. But as the Orders under review explain, the bar to "buy/sells" "applies to all firm capacity that is subject to the Order No. 636 capacity release program." Thus, in the now-prohibited transactions, an LDC holds title to gas specifically purchased by the LDC for the customer while utilizing its firm capacity rights to transport the designated gas over the interstate pipeline. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117. It is not, of course, necessarily the identical gas that the end-user receives at the delivery point.

Commission in the El Paso proceedings were conducted under the authority and oversight of the California Public Utility Commission.

FERC acknowledges that "buy/sell" transactions implicate legitimate state regulatory interests. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117, at 61,383-84. That said, given the transactions' intermediate stage — in which the end-user expressly arranges for the interstate transportation of specifically identified gas — the Commission contends that it has authority to preempt such state regulation. We therefore begin by setting forth settled principles of federal preemption.

a. *Introduction to federal preemption*

The Constitution provides that the laws of the federal government "shall be the supreme Law of the Land; . . . any Thing in the Constitution or Laws of any state to the Contrary notwithstanding." U.S. CONST. art. VI. That principle of supremacy is implemented through the doctrine of federal "preemption,"[70] under which state and local law may be stripped of its effect. Federal preemption may occur in a variety of circumstances:

> [1] It is well established that within constitutional limits Congress may pre-empt state authority by so stating in express terms.

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70. *See generally New York St. Conf. v. Travelers Ins. Co.*, __ U.S. __, __ - __, 115 S.Ct. 1671, 1676-77, 131 L.Ed.2d 695 (1995); *Cipollone v. Liggett Group*, 505 U.S. 504, 516, 112 S.Ct. 2608, 2617, 120 L.Ed.2d 407 (1992); *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248, 104 S.Ct. 615, 621, 78 L.Ed.2d 443 (1984); *Florida Lime & Avocado Growers v. Paul*, 373 U.S. 132, 141-42, 83 S.Ct. 1210, 1216-17, 10 L.Ed.2d 248 (1963).

> [2] Absent explicit pre-emptive language, Congress' intent to supersede state law altogether may be found from a scheme of federal regulation so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it, because [(a)] the Act of Congress may touch a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject, or [(b)] because the object sought to be obtained by the federal law and the character of obligations imposed by it may reveal the same purpose. [3] Even where Congress has not entirely displaced state regulation in a specific area, state law is pre-empted to the extent that it actually conflicts with federal law. Such a conflict arises when compliance with both federal and state regulations is [(a)] a physical impossibility, or [(b)] where state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.

Pacific Gas & Elec. Co. v. State Energy Resources Conserv. & Devel. Comm'n, 461 U.S. 190, 203-04, 103 S.Ct. 1713, 1722, 75 L.Ed.2d 752 (1983) (internal citations, quotation marks, and ellipses omitted).

Moreover, federal preemptive authority may be exercised not only through federal statutes but also regulations issued by

administrative agencies.[71] When an agency announces its intent to pre-empt state authority in a particular area,

> the correct focus is on the federal agency that seeks to displace state law and on the proper bounds of its lawful authority to undertake such action. The statutorily authorized regulations of an agency will pre-empt any state or local law that conflicts with such regulations or frustrates the purposes thereof. Beyond that, however, in proper circumstances the agency may determine that its authority is exclusive and pre-empts any state efforts to regulate in the forbidden area. It has long been recognized that many of the responsibilities conferred on federal agencies involve a broad grant of authority to reconcile conflicting policies. Where this is true, the Court has cautioned that even in the area of pre-emption, if the agency's choice to pre-empt represents a reasonable accommodation of conflicting policies that were committed to the agency's care by the statute, we should not disturb it unless it appears from the statute or its legislative history that the accommodation is not one that Congress would have sanctioned.

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71. *See generally Fidelity Fed. Sav. & Loan Ass'n v. de la Cuesta*, 458 U.S. 141, 152, 102 S.Ct. 3014, 3022, 73 L.Ed.2d 664 (1982); *Lincoln Sav. & Loan Ass'n v. Federal Home Loan Bank Bd.*, 856 F.2d 1558, 1560-61 (D.C.Cir.1988); *Conference of St. Bank Super. v. Conover*, 710 F.2d 878, 881-83 (D.C.Cir.1983).

City of New York v. FCC, 486 U.S. 57, 64, 108 S.Ct. 1637, 1642, 100 L.Ed.2d 48 (1988) (citations and quotation marks omitted) (emphasis added).

b. *Analysis*

We consider petitioners' arguments regarding "buy/sell" transactions under the branch of pre-emption doctrine that concerns "conflicts" between state and federal law, and particularly state law that "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Hines v. Davidowitz*, 312 U.S. 52, 67, 61 S.Ct. 399, 404, 85 L.Ed. 581 (1941). The Commission's goal in preempting "buy/sell" transactions was to preserve the integrity of its uniform capacity release program. *See El Paso Natural Gas*, 60 F.E.R.C. ¶ 61,117, at 61,385. Specifically, the Commission concluded that "buy/sells" offer a ready means of circumventing the open, nondiscriminatory bidding process central to capacity release. Under Order No. 636, an end-user seeking firm interstate transportation for gas that it has identified or acquired at the point of production must attempt to purchase capacity by contracting on the open market. In a "buy/sell" transaction, in contrast, the end-user can contract with an LDC without being forced to compete with other shippers that value the capacity. FERC reasoned that because "buy/sells" occur without open bidding, and result in the tying-up of interstate pipeline capacity, they circumvent and distort the transportation market envisioned by Order No. 636.[72]

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72. Hadson Gas Co. suggests that FERC "ignored relevant differences among shippers" in prohibiting all "buy/sell" arrangements, without regard to the market power of the particular shipper. In particular, Hadson contends that while LDCs may hold sufficiently substantial capacity rights to exercise

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The LDCs contend that preemption is inappropriate in this instance because the Commission's prohibition on "buy/sells" constitutes a regulation of the retail sale of natural gas, which Congress reserved to the jurisdiction of state regulatory bodies. While the Commission emphasizes the intermediate, transportation stage of the transaction, the LDCs focus on the terminal stage, describing "buy/sell" agreements as a classic instance of an LDC making a retail sale to a retail customer. *Cf. AGD I*, 824 F.2d at 995 ("LDCs purchase gas for resale to end users, large and small. Their services and prices are subject to state regulation but not to that of FERC."). As the LDCs characterize the transaction:

> A retail customer participating in a buy/sell arrangement with an LDC purchases the same product purchased by other retail gas customers: natural gas, delivered to the point of consumption, at a state-regulated price that includes the cost of (a) the gas; (b) the inter- and intrastate transportation required to move the gas from the market or production area to the point of consumption; and, (c) all other local distribution services, such as balancing and metering costs.

LDCs' Reply Br. at 8. Further, given the express terms of NGA

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market power, the same cannot be said of gas marketers. As FERC notes, however, when the capacity available for sale on a particular pipeline is limited, holders of even relatively small capacity allotments can exercise market power. Further, holders of smaller capacity shares are able to increase their market power by pooling their holdings and marketing them together. *See* Order No. 636-A, ¶ 30,950, at 30,558.

§ 1(b), the LDCs maintain that the Commission's jurisdiction cannot arise merely by means of some effect of "buy/sell" agreements on interstate transportation; such an interpretation of the Act would dramatically expand FERC's jurisdiction because almost all gas travels interstate and therefore almost all retail sales of gas affect interstate transportation. *See also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 308, 108 S.Ct. 1145, 1155, 99 L.Ed.2d 316 (1988) ("Of course, every state statute that has some indirect effect on rates and facilities of natural gas companies is not preempted."). Thus, conflict preemption analysis must be applied with particular care in those instances in which the Commission seeks to preempt state regulation merely because it has some effect on the interstate transportation of natural gas. *Northwest Central Pipeline v. State Corp. Comm'n*, 489 U.S. 493, 515- 16 & n. 12, 109 S.Ct. 1262, 1276-77 & n. 12, 103 L.Ed.2d 509 (1989).

We believe that the LDCs have confused two separate issues. While the Commission's rationale in preempting "buy/sells" is the transactions' effect on interstate transportation — namely, that "buy/sells" facilitate circumvention of the capacity release program — the Commission's authority is grounded in the transaction itself.[73] In the intermediate stage of a "buy/sell" transaction, the LDC carries the gas identified by the end-user

73. Indeed, it is in truth the LDCs that would bootstrap jurisdictional implications to the effects of Order No. 636. According to the LDCs, "buy/sell" agreements allow them to distribute and utilize their capacity rights more efficiently. This has as a secondary effect "lowering the unit cost of gas to" end-users, which the LDCs characterize as a "traditional and legitimate state interest[ ]." That proposition sweeps far too broadly. Almost every element of the Commission's regulation of interstate transportation affects distributors' costs, which must be passed on to local end-users. Regulation of interstate transportation is not thereby converted into a ground for exclusive state jurisdiction.

on its own firm capacity and under its own title on an interstate pipeline. Contrary to the LDCs' characterization, FERC's jurisdiction arises from the transportation itself; interstate transportation of gas selected by the end-user is a central element of the parties' agreement. As FERC states in its brief, "buy/sells" are "at bottom nothing more than agreements by which firm shippers allocate space on an interstate pipeline to customers who negotiate their own wellhead transactions." Transactions that do not include this transportation element are not "buy/sells" and are not preempted.

In a standard retail sale, by contrast, the end-user purchases gas from an LDC at the local delivery point without regard to aspects of gas transportation at points further upstream. *See id.* at 97 ("Traditional LDC retail sales consisted of sales of gas to local customers from generic system supply through local distribution facilities after the gas had completed its interstate journey."). Order No. 636 does not prohibit or condition such sales. Nor does the Order preempt state regulatory agencies from modifying an LDC's rate structure to accommodate differences in local conditions. Further still, LDCs remain free to sell gas to retail customers under the terms and conditions set by state regulators. Under Order No. 636, an end-user that would previously have engaged in a "buy/sell" transaction will still purchase the gas from the producer and still receive the gas at its delivery point. The crucial difference is that the end-user must purchase capacity rights from the LDC in the open market through the capacity release mechanism rather than by transferring title to the gas to the LDC and regaining title at the local delivery point.

Accordingly, we sustain the Commission's determination to pre-empt state regulation of "buy/sell" transactions. FERC's

effort to avoid circumvention of its capacity release regulations "represents a reasonable accommodation of conflicting policies that were committed to [its] care" under the Natural Gas Act. *City of New York*, 486 U.S. at 64, 108 S.Ct. at 1642. Further, given that the regulations do not impinge upon state control over retail gas sales, it appears that the Commission's accommodation is one that Congress would have sanctioned. *See id.*

C. *Substantive Challenges*

1. *Exclusion of Part 157 shippers from capacity release*

In Order No. 636-A, the Commission concluded that only "Part 284" blanket-certificated shippers would be permitted to engage in capacity release and utilize flexible receipt and delivery points. Order No. 636-A, ¶ 30,950, at 30,565. The Electric Generator Petitioners ("Electric Generators") contend that FERC's exclusion of Part 157 "individually certificated" shippers[74] was arbitrary and capricious. Their theory is that capacity release and flexible receipt and delivery points were intended to compensate for the greater costs of straight-fixed-variable rate design, which both Part 284 and Part 157 shippers are subject to; excluding Part 157 shippers from capacity release therefore allegedly deprives them of a necessary and equivalent means of cost mitigation. They also contend that subjecting Part 157 shippers to SFV rate design while excluding them from capacity release is unduly discriminatory, given that both SFV

74. These shippers transport gas pursuant to individual certificates issued by the Commission under Part 157 of its regulations. The critical difference between Part 157 and Part 284 shippers is that Part 157 shippers have always been able to transport non-pipeline owned gas, while Part 284 shippers generally have had that capability only since the promulgation of Order No. 436. *See MPC I*, 761 F.2d at 782.

rate design and capacity release were intended to develop a national natural gas market.

The Commission's decision to exclude Part 157 shippers from capacity release and flexible receipt and delivery points was not arbitrary and capricious. While capacity release does ameliorate the costs of SFV rate design, it was never intended as the central cost-mitigation measure, *see* Order No. 636-A, ¶ 30,950, at 30,594, 30,597-98, for there are specific mechanisms in place intended to address the particular costs associated with SFV, including alternative ratemaking techniques, phase-in measures, and the continued use of one-part rates for small customers. *See infra* Part IV.C.1. Moreover, allowing individually certificated shippers to utilize capacity release would in effect require Part 284 shippers to subsidize their Part 157 counterparts, given that Part 284 shippers pay costs that Part 157 shippers do not.[75] Specifically, Part 157 shippers are not required to pay the transition costs of Order No. 636, and

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75. The Electric Generators maintain that their exclusion from capacity release represents a downgrade in their service because Order No. 636 also prohibited them from selling capacity under the Commission's predecessor "capacity brokering" program. They contend that because the Commission is eliminating a pre-existing program, it is obligated to offer a particularly persuasive rationale for its decision. *Cf. Williams Natural Gas Co. v. FERC*, 872 F.2d 438, 444 (D.C.Cir.1989). But, as FERC notes, capacity brokering was authorized on only a few pipelines, so that widespread capacity release is in fact a major service upgrade. Moreover, the Commission's rationale in implementing capacity release applies equally to its decision to bar Part 157 customers from continuing to engage in capacity brokering, and is persuasive. Finally, as the Commission maintains, and the Electric Generators essentially concede in their reply brief, FERC's policy granting Part 157 shippers access to capacity brokering "was a settlement, was expressly limited to the facts in that proceeding, was adopted only on an interim basis, and was never intended to survive Order No. 636."

their transportation arrangements are not subject to pre-granted abandonment. Further, the Commission prohibits Part 157 shippers, which do not operate under open-access provisions, from including unique terms and conditions in their contracts in order to avoid undue discrimination. For that very reason, the Commission prohibits Part 157 shippers from granting discounts, which itself presents a major obstacle to Part 157 shippers' participation in capacity release because competitive bidding presumes the ability to offer a lower price.

The Electric Generators reply that these factors have no connection to the cost-mitigation effects of the capacity release program. The more salient issue, however, is whether the factors identified by either the Commission or the Electric Generators have any intrinsic connection to SFV rate design; they do not. Fundamentally, the petitioners contend that they are entitled to release capacity as one way of making up for the costs of SFV. FERC replies, quite sensibly, that while capacity release would reduce the Electric Generators' costs, including costs associated with SFV, the Electric Generators are already receiving cost benefits not available to Part 284 customers, and are not entitled to further benefits.

Nor was the Commission's decision to exclude Part 157 shippers unduly discriminatory. The Commission applied SFV rate design to both Part 284 and Part 157 shippers because both generally have been subject to the same rate design. *See* Order No. 636-B, ¶ 61,272, at 61,992. Even if the goal of both SFV rate design and capacity release is the creation of a national gas market, that does not mean that FERC's decision to apply only one to Part 157 shippers constitutes undue discrimination. "[T]he competitive rationale for adopting SFV rate design as a means to promote the development of a national gas market applies

equally to [Part 284 and] Part 157 rates." *Id.* While allowing Part 157 shippers to engage in capacity release might expand the national gas marketplace, as we have explained, it would also give them an unfair subsidy over Part 284 shippers. As FERC notes in its brief, "[g]iven the significant differences between these two forms of service under Order No. 636, it was not unreasonable to confine the capacity release program to Part 284 open access service." We see no reason to disturb the Commission's conclusion that those cost considerations outweighed any benefit to the national gas marketplace and disentitled Part 157 shippers from engaging in capacity release.

Moreover, as the Commission explains, the Electric Generators may receive access to capacity release and flexible receipt and delivery points by converting to Part 284 service. This does not mean, as petitioners contend, that the Commission is unlawfully attempting to leverage the Electric Generators' conversion. Here, we reject petitioners' reliance on *National Fuel Gas Supply Corp. v. FERC*, 909 F.2d 1519 (D.C.Cir.1990). In *National Fuel*, this court turned back an effort by FERC to condition its certification of a Part 157 shipper's gas services on the shipper's obtaining a blanket Part 284 certificate as well. Our ruling there was based on the fact that the Commission had already determined that a Part 157 certificate was "required by the public convenience and necessity" when it nonetheless attempted to add the additional condition of acquiring a Part 284 certificate. Given the Commission's conclusion that the shipper was already entitled to a Part 157 certificate, "[i]t was thus clear at the outset that the Commission considered certification . . . to be in the public interest regardless of whether the pipeline also accepted a blanket transportation certificate." *Id.* at 1522. FERC therefore lacked authority to deny the shipper a Part 157 certificate. In this case, in contrast, the Electric

Generators do not contend that the Commission has determined that Part 157 shippers have the right to engage in a certain service, but is nonetheless denying them the right to engage in it. Moreover, even under the petitioners' far more expansive reading of *National Fuel*, this is not an instance in which FERC is attempting to coerce a conversion from Part 157 to Part 284 service; the Commission is simply pointing out that conversion offers the Electric Generators one means of cost-mitigation.

2. *The standard for determining the best bid*

The LDCs and Industrial End-Users raise three challenges to the methods selected by the Commission for determining the prevailing bidder and price in the capacity release transaction. In Order No. 636, FERC concluded that conditions set by LDCs on their release of capacity "must not prefer any shipper, such as an end-user, over other shippers, and cannot take into account the use of the LDC's own facilities." Order No. 636-B, ¶ 61,272, at 61,997. The LDCs maintain that, in a market sense, this rule prohibits them from selecting what is truly the "best" bid, *i.e.*, "one that reflects [the] greatest economic benefit to the releasing shipper." Specifically, the LDCs want the right to favor their own end-users in capacity sales, a practice that ultimately would reduce the LDCs' own costs. But that is not a right to which they are entitled under the Natural Gas Act. The LDCs' claim is at bottom nothing more than an objection to FERC's open-access, nondiscrimination policy. The goal of capacity release is to create a uniform national market for transportation, not to maximize the benefit to LDCs. Only by utilizing nondiscriminatory factors in determining the prevailing bid can FERC ensure that the shipper that places the highest value on capacity receives it.

The Industrial End-Users make the related argument that FERC acted arbitrarily in refusing to grant a bidding preference to LDCs' existing end-users. In particular, they note that FERC did grant existing end-users a preference in acquiring capacity released by upstream pipelines under the section 284.242 mandatory capacity release program. As with the immediately preceding claim, however, the standard set by FERC fundamentally is part of its nondiscrimination and open-access policy. Moreover, as FERC notes, an end-user can be sure of receiving capacity by entering into a pre-arranged deal with its LDC at the maximum allowable price.[76] The preference granted under the mandatory program, in contrast, is unrelated to the development of a transportation market through capacity release; it is specifically intended to ensure that when pipelines engage in unbundling, their end-users are not deprived of the transportation necessary to fulfill their pre-existing gas needs.

The Electric Generators finally contend that FERC should not uniformly have set the maximum allowable rate for resales of capacity at the originally determined maximum rate. They contend that this will in some instances result in discrimination against shippers who pay higher initial "incremental" rates.[77] The Commission responds that this issue is too complex and fact-bound to address in the overarching Order No. 636

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76. While an LDC could conceivably refuse to make such a deal, it would have no incentive to do so because no other transaction can provide it with a higher price. Further, as the Commission notes in its brief, claims that an LDC discriminated against its end-users in allocating capacity may be addressed through the NGA § 5 complaint procedure.

77. For a discussion of incremental rates, *see generally TransCanada PipeLines Ltd. v. FERC*, 24 F.3d 305, 308-11 (D.C.Cir.1994); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312-14 (D.C.Cir.1991).

proceedings, and that it should be deferred to the restructuring proceedings, where a better record can be developed. *See* Order No. 636-A, ¶ 30,950, at 30,561 ("[T]he parties in restructuring proceedings involving incremental rates should consider and propose methodologies to ensure that the capacity release mechanism operates efficiently and that all parties are treated fairly and equitably, without undue discrimination."). We agree. The Electric Generators' explication of their claim in these proceedings is far too sparse to allow for reasoned evaluation, primarily because the relevant factual record is not before us. Their claim may properly be evaluated by the Commission in individual restructuring proceedings where further facts can be developed.

3. *Interruptible transportation revenue crediting*

After the implementation of capacity release under Order No. 636, the number of firm transportation sellers in the marketplace substantially increased. As a result, it became difficult for pipelines to determine how much demand there will be for interruptible transportation ("IT") service. In turn, it is difficult for the pipelines to determine what portion of their costs to recoup through billings to IT (as opposed to firm) service. In the Order No. 636 proceedings, FERC suggested that a pipeline

> might decide to attribute no revenue responsibility to interruptible transportation. Since the pipeline's firm shippers would be responsible for all pipeline costs, revenues from the sale of interruptible transportation would [later] be credited to the firm shippers.

Order No. 636-A, ¶ 30,950, at 30,563. Under true cost

accounting, 100% of IT revenues would be credited to firm shippers, because firm customers are essentially being overcharged until the pipeline can figure out how much money it is recovering from IT service. The Commission suggested, however, that pipelines might adopt a 90/10 mechanism, under which only 90% of IT revenues would be credited to firm shippers. This 10% difference was thought by FERC to be a necessary incentive for pipelines to market interruptible transportation. Without it, pipelines would be assured of recovering their costs through firm sales charges, and therefore would have no reason to maximize IT throughput.

The Industrial End-Users, who utilize interruptible transportation, challenge the Commission's endorsement of a 90/10 IT revenue crediting mechanism on two grounds. First, they argue that the 10% gain creates an insufficient incentive for pipelines to market IT. The Industrial End-Users note that FERC rejected proposals for revenue crediting under Order No. 436, because they "give[ ] the pipeline little or no incentive to provide service under the rule." Order No. 436, ¶ 30,665, at 31,537. Second, they argue that the 90/10 mechanism reduces other shippers' incentive to release capacity; shippers know that if they do not put their firm capacity on the market, thereby forcing other companies to utilize IT service, they will receive some portion of the IT revenues through the crediting mechanism anyway. We conclude that the Industrial End-Users' challenge to the IT revenue crediting mechanism is premature. Order No. 636-A expressly provides that pipelines "might" adopt this "potential approach," and that "parties to the restructuring proceedings also may consider whether other methods are needed." Order No. 636-A, ¶ 30,950, at 30,563; *see also* Order No. 636-B, ¶ 61,272, at 62,000 ("[T]he parties to the restructuring proceedings could consider a variety of approaches,

such as agreeing on an appropriate level of throughput for interruptible transportation or some type of revenue crediting mechanism.").[78] Our concerns are magnified given that the Industrial End-Users maintain that the 10% pipeline credit does not provide pipelines with a sufficient incentive to market IT, but provide no data or explanation of why that is the case. The only way to evaluate their claim is in the light of the particular facts presented in individual pipelines' restructuring proceedings. *See id.* ("The petitioners requesting rehearing have not been aggrieved by the suggestion that the Commission would consider a revenue crediting approach proposed in a specific restructuring proceeding. In implementing its regulations, the Commission will not adopt rigid rate-making methodologies that fail to reflect the reality of the market or the intent of its regulations."). We therefore defer resolution of the Industrial End-Users' IT revenue crediting challenge to the individual pipeline restructuring proceedings.

D. *Conclusion*

We deny the petitions for review insofar as they dispute the Commission's jurisdiction over capacity release transactions. We further deny the petitions for review insofar as they challenge (1) the exclusion of Part 157 shippers from the capacity release program, (2) the mechanism chosen by the Commission for determining the best bid in capacity release transactions, and (3) the Commission's suggestion that a 90/10 mechanism is an appropriate means of crediting interruptible transportation revenues. We specifically defer to later proceedings

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78. While the Industrial End-Users contend that the Commission has been applying the 90/10 mechanism as a rigid rule, they concede that it approved an 80/20 mechanism in *CNG Transmission Corp.*, 64 F.E.R.C. ¶ 61,082, at 61,776-66 (1993).

consideration of the merits of both the revenue crediting mechanism and the Commission's treatment of incremental rates.

IV. Rate Design

Various petitioners raise three major challenges to the rate design portion of the Order No. 636 series. As noted above, FERC ordered a change from the preexisting modified fixed variable (MFV) to a straight fixed variable (SFV) rate design. First, petitioners question whether FERC has authority under the NGA to adopt SFV rate design. Second, they question whether FERC's decision to switch from MFV rate design to SFV rate design was a reasonable one. Third, they question whether the mitigation measures FERC employed to ease the shift to SFV rate design are within FERC's ratemaking discretion.

A. *FERC's Authority to Adopt SFV Rate Design*

1. *MFV rate design's anticompetitive effects*

FERC's authority over rate design in this case derives from NGA § 5, which requires it to replace any "unjust, unreasonable, unduly discriminatory, or preferential" rate, charge or classification charged "by any natural-gas company in connection with any transportation or sale of natural gas" with a "just and reasonable rate, charge, [or] classification." 15 U.S.C. § 717d. Under the preexisting MFV design, the pipelines incorporated into commodity charges to their sales customers and usage charges to their transportation customers fixed costs that varied greatly from pipeline to pipeline. Accordingly, the unit prices to gas customers did not accurately reflect the actual

variable cost of supplying gas, because producers in different gas fields "compete for market share via different pipelines," so that their competitive positions in the market reflected the fixed costs in the pipelines' respective transportation usage charges and not simply "the producers' own costs and efficiencies in producing gas." Order No. 636, ¶ 30,939, at 30,434. The Commission concluded that a shift to the SFV rate design, under which the usage charges accurately reflect the actual variable costs of delivering gas, would remove this impediment to efficient competition.

The LDC petitioners[79] argue that FERC had no authority to take regulatory action on the basis of MFV rate design's anticompetitive effects on gas producers. They admit that FERC must consider the anticompetitive effects of rate design systems, but contend that FERC can only consider the anticompetitive effects of a system on entities it regulates directly (*i.e.*, pipelines themselves), not on unregulated industries such as gas producers, and they argue that MFV's anticompetitive effect on gas suppliers does not constitute an anticompetitive effect on pipelines. The LDCs cite in support of their position *Official Airline Guides, Inc. v. Federal Trade Comm'n*, 630 F.2d 920, 927-28 (2d Cir.1980), *cert. denied*, 450 U.S. 917, 101 S.Ct. 1362, 67 L.Ed.2d 343 (1981), in which the Second Circuit struck down a Federal Trade Commission (FTC) ruling that a monopoly airline guide publisher's refusal to publish flight schedules for certain airlines impaired competition in the airline industry. The Second Circuit held that the FTC Act's power to proscribe anticompetitive conduct did not extend to the restraint of a business's practices solely because of the conduct's incidental effect on competition between third parties in another industry.

79. LDC petitioners presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co. Washington Gas Light Co. is a supporting intervenor.

As the LDCs stress, antitrust policy "does not outlaw the practices of a party solely because those practices may indirectly affect competition between other entities with which it does not compete." Though the LDCs' premise is valid, it does not answer the question of whether FERC has the authority to consider anticompetitive effects on unregulated segments of the gas industry in setting rates for the regulated pipelines. The Second Circuit's decision simply does not purport to answer that question. Rather, the Official Airline Guides court was extending the doctrine established in *United States v. Colgate & Co.*, 250 U.S. 300, 307, 39 S.Ct. 465, 468, 63 L.Ed. 992 (1919) (as quoted in Official Airline Guides, 630 F.2d at 925), that, "[i]n the absence of any purpose to create or maintain a monopoly," antitrust policy "does not restrict the long recognized right of trader or manufacturer engaged in an entirely private business, freely to exercise his own independent discretion as to parties with whom he will deal." In fact, the Official Airline Guides court noted the dangers of departing from this principle of independent business judgment: "[W]e think enforcement of the FTC's order here would give the FTC too much power to substitute its own business judgment for that of the monopolist in any decision that arguably affects competition in another industry." *Official Airline Guides*, 630 F.2d at 927.

In contrast, FERC's decision in Order No. 636 represents not the rolling back of an independent business judgment because of its anticompetitive effect on an unrelated industry, but rather the substitution of one administratively imposed ratemaking regime for another based on the anticompetitive effect of the preexisting regime on unregulated entities dealing through regulated entities in a partially regulated segment of the economy — that is, the regulated pipeline segment of the partially regulated natural gas industry. The Commission's

express duty under NGA § 5 to set aside rates and practices that it finds unjust, unreasonable, unduly discriminatory, or preferential is not limited to the remedies that the FTC may order in an unregulated market; nor is FERC's basis for the exercise of that authority necessarily as limited as the FTC's bases for enforcement decisionmaking. Antitrust policies governing the FTC in the unregulated market do not exhaust the public interest grounds on which the Commission may order a change in rates under NGA § 5. Here, given that we review the Commission's acts under the deferential "substantial evidence" standard, 15 U.S.C. § 717r(b); *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C.Cir.1992), we hold that the Commission adequately justified its exercise of its authority when it stated that its ratemaking authority "includes the establishing of just and reasonable transportation rates that maximize the benefits of decontrol to gas consumers," Order No. 636-A, ¶ 30,950, at 30,594-95, and that regulated transportation rates "should in no way inhibit the creation of a national gas market of efficient gas merchants as envisioned by Congress in enacting the Decontrol Act." Order No. 636, ¶ 30,939, at 30,433. Unlike the FTC in *Official Airline Guides*, FERC was not attempting to limit the options of a free business actor in order to promote competition in an adjacent industry, but only to prevent the regulatorily imposed price decisions of a regulated industry from creating anticompetitive factors in economically adjacent markets.

2. *SFV rate design and NGA § 5*

The PUCs argue that FERC's ordering of the switch to SFV rate design exceeds its statutory authority. Under the NGA, FERC draws its ratesetting authority from two sections: NGA § 4 (15 U.S.C. § 717c) authorizes FERC to accept or reject rates

and rate adjustments filed by natural gas companies; and NGA § 5 (15 U.S.C. § 717d) authorizes FERC after a hearing and upon findings that an existing rate is "unjust, unreasonable, unduly discriminatory, or preferential" to fix "just and reasonable rate[s] . . . by order." The PUCs contend, and FERC admits if we reach the merits, that the Commission draws its authority in the present restructuring from § 5, or not at all, as no natural gas company has filed the rate structure which FERC is imposing. The PUCs argue that FERC's order imposing the new rate structure exceeds its authority under § 5 because that section expressly provides "[t]hat the Commission shall have no power to order any increase in any rate contained in the currently effective schedule" then on file with the Commission. Because the new rate structure will result in an increase in charges to some customers, the PUCs argue that FERC's order violates this provision.

FERC first contends that this rate increase argument is not properly before the court "because none of these petitioners raised it before the Commission in their requests for rehearing of Order No. 636." As FERC rightly suggests, the party who raises an issue in a petition for review must have raised the same issue in its petition for rehearing before the agency. *ASARCO, Inc. v. FERC*, 777 F.2d 764, 773-75 (D.C.Cir.1985). However, Atlanta Gas Light Company (Atlanta) and Chattanooga Gas Company (Chattanooga) specifically raised the rate increase argument in their petition for rehearing of Order No. 636. Request of Atlanta Gas Light Company and Chattanooga Gas Company for Rehearing and Clarification at 14-16 (May 8, 1992). And in the LDCs' brief in this court, several LDCs (including Atlanta and Chattanooga) cross-reference the PUCs' presentation of the rate increase argument, thereby incorporating the argument into the LDC brief before us, because Atlanta and

Chattanooga raised the rate increase argument in their petition for rehearing before FERC and raise it again in the present proceeding, the argument is properly before us, and we must consider it on its merits.

In Order No. 636-A, FERC disposed of the rate increase argument by relying on *ANR Pipeline Co. v. FERC*, 863 F.2d 959 (D.C.Cir.1988). In that case a pipeline filed a § 4 schedule to implement a rate reduction. Order No. 636-A, ¶ 30,950, at 30,666. FERC, using its § 5 authority, determined that the pipeline's rate design methodology was unjust and unreasonable (when a pipeline files a § 4 rate schedule, FERC can transform the proceedings into a § 5 action. *Western Resources, Inc. v. FERC*, 9 F.3d 1568, 1579 (D.C.Cir.1993)), and ordered the company to implement MFV rate design and to eliminate its minimum billing practice. Under the minimum billing practice, certain customers "were obligated to pay ANR, in each contract year, an amount equal to the fixed-cost portion of the commodity rate times the greater of (1) the volume actually purchased by the customer, or (2) a 'minimum bill quantity' (MBQ) specified by contract." *ANR Pipeline*, 863 F.2d at 960; *see also supra* at 68 n. 29 (describing minimum billing practices). One of ANR's largest customers, Michigan Consolidated Gas Company (MichCon), was paying more than its allocatable share of fixed costs because of the minimum bill requirement. *ANR Pipeline*, 863 F.2d at 960. Once ANR eliminated the minimum bill in compliance with FERC's order, it recalculated the per-unit share of fixed costs based on the decreased number of total units over which to allocate fixed costs. (After eliminating the minimum bill, the projected number of units over which to allocate fixed costs necessarily decreased for MichCon, since MichCon had not purchased and was not expected to purchase the MBQ of gas.). As a result, the per-unit share of fixed costs incorporated in the commodity charge went up.

Appendix A

Although FERC initially rejected ANR's proposed "increase" in commodity rates as a violation of the filed rate doctrine, we reversed that decision, concluding that FERC "had not rationally explained why its requirement that ANR's minimum bill had to be removed would not authorize the removal of volumes attributable to the minimum bill for purposes of calculating the amount of the fixed-cost commodity charge." Order No. 636-A, ¶ 30,950, at 30,667. The Commission therefore reads *ANR Pipeline* as standing for the proposition that "when the Commission orders a pipeline to implement a different rate design method that requires reductions in one component of the pipeline's rates, it must permit the pipeline to implement offsetting increases in some other component simultaneously in order for the pipeline to recover its cost of service." *Id.*

FERC's argument based on *ANR Pipeline* is a powerful one. Our reasoning in *ANR* supports a small scale version of the large scale balanced restructuring with offsetting features that FERC has ordered in the present proceeding. *ANR* is not, however, totally dispositive. The issue in that case came to us at a later stage. In *ANR*, after the Commission had made its initial § 5 ruling, the pipeline had made a compliance filing. That filing incorporated the contested "increase." Reviewing FERC's rejection of the compliance filing, we could not conclude that the Commission had "rationally explained why that filing [did] not comport with" the earlier instruction to the submitting pipeline. *ANR Pipeline*, 863 F.2d at 964. We did not therefore purport to authoritatively decide the breadth of the limitation in § 5 providing "that the Commission shall have no power to order any increase . . . unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d. That is, we did not determine how that section applies in the case of a Commission-initiated rate restructuring which,

while reducing rates for some customers, necessarily offsets that reduction by an at least present increase in the share borne by others. Thus, *ANR* is at best persuasive rather than controlling authority in favor of the Commission's asserted power to order a restructuring that results in increasing some components to the detriment of some pipeline customers.

Also relevant to our determination of the issue is our decision in *Western Resources Inc. v. FERC*, 9 F.3d 1568 (D.C.Cir.1993). In that case, the existing schedule included a "forward-haul rate" of approximately 20.05 cents per Mcf and a "backhaul rate" of one cent per Mcf. *Id.* at 1571. The pipeline filed a § 4 revised tariff sheet featuring increases in both the forward-haul and backhaul rates, making them equal to one another at a level above the former 20.05 cents per Mcf forward-haul rate. *Id.* FERC approved the forward-haul rate increase, but set the new backhaul rate at one-half the forward-haul rate. *Id.* at 1571-72. We remanded the case to FERC, however, holding that it had failed to sufficiently justify its decision as to the forward-haul rate and that it had improperly concluded that it could use its § 4 authority to grant half the requested backhaul increase. We determined that FERC's decision to increase the backhaul rate to only half the level requested was so far removed from the requested increase that it constituted an exercise of § 5 authority and not § 4. *See id.* at 1578-79. We remanded the backhaul increase on the grounds that FERC had not met the burden of proof imposed on it by § 5. *See id.* at 1580. Our opinion in *Western Resources* is susceptible of two interpretations. First, because we remanded for further consideration rather than vacating altogether a Commission order that amounted to a restructuring under § 5 including component increases, we implicitly concluded that FERC had the general authority to conduct such restructuring and only remanded for a

determination as to FERC's use of that authority on the specific rate before it. In *Western Resources*, the turning point of our decision was that FERC had erroneously purported to use § 4 authority where it was unavailable. As § 5 authority was the only authority left, if FERC had acted properly at all, it must have been under § 5. Our *Western Resources* opinion is also subject to the interpretation that in that case we remanded to FERC for the possibility of a rate decrease under § 5, considering the relevant baseline to be the pipeline's § 4 submission, which proposed rates higher than those that the Commission was willing to approve. Under the first of these possible interpretations, our remand to the Commission to reconsider its action under § 5 may carry some implication that we deemed it to have the authority it purports to use now, but that implication is not a strong one, and again, our existing circuit law at most inclines us toward FERC's position but does not compel us to adopt it. Under the second possible interpretation of *Western Resources*, the case is simply not on point at all.

We therefore today for the first time authoritatively determine the issue of whether a § 5 rate restructuring that includes an increase in some rate components to the detriment of some customers amounts to a prohibited "rate increase" under § 5 itself. As FERC claims this authority under the Natural Gas Act, a statute committed to its administration, we review the Commission's decision under the deferential standard dictated in *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842-43, 104 S.Ct. 2778, 2781-82, 81 L.Ed.2d 694 (1984). At the first step of that familiar two-step inquiry, we ask "whether Congress has directly spoken to the precise question at issue." *Id.* at 842, 104 S.Ct. at 2781. That is the point at which our inquiry ends "if we can come to the unmistakable conclusion that Congress had an intention on the

precise question at issue," Nuclear *Information Resource Service v. NRC*, 969 F.2d 1169, 1173 (D.C.Cir.1992) (in banc) (internal quotations and citations omitted). This is not such a case.

In reaching that conclusion we have examined first the plain language of the statute. The relevant text states: "[T]he Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d(a). At first reading, it may be most natural to suppose that Congress included within the prohibition against "any increase in any rate" a preclusion of Commission orders for rate restructuring that would ultimately lead to rate increases for some pipeline customers. However, supposition and first reading are not the stuff of unambiguous expressions of intent, and the plain language does not convince us that Congress unambiguously intended the interpretation petitioners support. To further inform our inquiry into congressional intent, we examine the complete statutory scheme. *Davis v. Michigan Dep't of the Treasury*, 489 U.S. 803, 809, 109 S.Ct. 1500, 1504, 103 L.Ed.2d 891 (1989) ("It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme."). The scheme considered under the NGA today contemplates that FERC must act consistently with the Natural Gas Wellhead Decontrol Act of 1989, Pub.L. No. 101-60, 103 Stat. 157 (1989), as well. That enactment contemplates a considerably changed natural gas world in which regulation plays a much reduced role and the free market operates at the wellhead. While a court construing congressional intent in one enactment should not be too greatly influenced by the enactments of a later Congress, we must necessarily consider the duties faced by an agency in examining its construction of its enabling

acts. While this part of our analysis usually occurs at the second step of *Chevron*, it is not irrelevant to the first. A commission charged with the regulation of the rates of an industry may be expected to restructure its general mandates when its world changes. If the enabling act under which it operates can be construed so as to give it that authority, that construction should not be ruled out in the absence of a genuinely unambiguous expression of a congressional intent to the contrary. The general language prohibiting "rate increases" under § 5 is not so plainly directed at such a preclusion.

Insofar as legislative history is an appropriate guide to the unambiguous intent of Congress, the little available in the present instance argues against rather than for the claim of unambiguous congressional intent advanced by petitioners. At the time of the adoption of the NGA, Representative Clarence Lea, a principal sponsor of the NGA and chairman of the committee which reported it to the House, declared that "[t]he purpose of [the amendment creating the § 5 rate increase prohibition] was to prevent any company's rates being raised over their objection, with the idea of stifling competition with a competitor." 83 CONG. REC. 9101 (1938) (Statement of Rep. Lea). Under this interpretation, the prohibition was included not so much for the protection of gas consumers from rate increases, but to protect a pipeline disfavored by FERC from suffering under FERC-imposed rate increases that would harm the pipeline's ability to compete. While it is not of course impossible for a statute to have two purposes, the intent advanced by Lea supports the proposition that Congress did not unambiguously intend that § 5 would protect customers from restructured rate designs ultimately leading to increased charges. In short, § 5 is not unambiguous. The provision may easily be read to prohibit FERC from ordering increases in specific filed rates while

leaving it free to order the restructuring of rates as it has attempted to do here.

As we have found that the statute is not unambiguous with respect to the specific issue before us, we proceed to the second step of the *Chevron* analysis. "At this stage, we defer to the agency's interpretation of the statute if it is reasonable and consistent with the statute's purpose." *Nuclear Information Resource Service*, 969 F.2d at 1173 (internal quotations and citation omitted). Having already observed in our step one analysis that the Commission's interpretation is consistent with the structure and purpose of the statute, we have no difficulty in finding that interpretation a reasonable one at step two. The petitioners' proffered interpretation is also a reasonable, indeed, perhaps a more natural interpretation of the statutory language. That, however, is not the standard. Even if we were convinced that the petitioners' interpretation were the better one, "we are not free to impose our own construction on the statute, as would be necessary in the absence of an administrative interpretation." *Id.* (internal quotations, brackets, and citation omitted). The only question is whether the agency's interpretation is reasonable and consistent with the statutory purpose. The answer to that question is yes. FERC undoubtedly has the authority to restructure pipeline rate calculation mechanisms, as long as it does so in an otherwise lawful manner and supports its actions with substantial evidence. Any restructuring, even if it does not alter a pipeline's revenues by one cent, will virtually always increase by some amount the charges that some individual customers pay and decrease the charges to some others. Reading § 5 in such a way that these increases for some customers constitute prohibited "rate increases" leads to the conclusion that FERC has no authority to restructure pipeline rates at all. FERC is not required to so interpret the statute.

Appendix A

B. *SFV Rate Design and Substantial Evidence*

1. *MFV rate design's distortions of the natural gas market*

For several decades, FERC's ratemaking regime has included some portion of a pipeline's fixed costs in the pipeline's commodity and usage charges. Over the years, it varied the specific percentage of fixed costs actually included in those charges, but it generally followed the principle that some portion of fixed costs should be recouped through quantity-dependent charges.[80] In 1986, the Seventh Circuit upheld FERC's 1983 adoption of the MFV rate design in use prior to the promulgation of Order No. 636. *See* Order No. 636, ¶ 30,939, at 30,432 (citing *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir.1986)). The PUCs argue that FERC cannot depart from this approved use of MFV rate design without giving a reasonable justification for doing so, and that FERC has failed to do so in the Order No. 636 series. They claim that FERC's determination that MFV distorts the gas market is inconsistent with prior FERC decisions and court rulings approving of MFV. Essentially, they maintain that if MFV was good in the past, it must still be good today. Additionally, the PUCs find plenty of evidence of competitive markets under MFV rate design, and they maintain that dropping MFV rate design is therefore improper. Finally, they stress that the full incorporation of fixed costs in variable charges seems to work well for the oil pipeline industry, so it should also work in the case of gas pipelines.

As the Supreme Court has noted, "[a]llocation of costs is

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80. It does appear that the Commission has used a rate design method similar to SFV in the distant past of natural gas regulation. *See, e.g., Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433, 437-39 (D.C.Cir.1947) (explaining the "demand-commodity formula").

not a matter for the slide-rule. It involves judgment on a myriad of facts." *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589, 65 S.Ct. 829, 833, 89 L.Ed. 1206 (1945). Although the relevant technology has changed since *Colorado Interstate Gas*, the point that "[r]ate-making is essentially a legislative function," *id.*, has not. Our task, then, is not to determine whether MFV rate design is superior to SFV rate design, but merely to determine whether FERC has "made a reasoned decision based upon substantial evidence in the record" in departing from MFV rate design. *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C.Cir.1992).

Initially, we note that the PUCs have mischaracterized FERC's decision to depart from MFV rate design. As FERC notes in its brief, "modifying pipeline rate design to promote competition is nothing new." The switch from MFV rate design to SFV rate design does not represent a reversal in ratemaking policy. FERC simply ordered a reallocation of fixed costs in pipeline rate design. The fact that the old system was labeled "MFV" and the new system "SFV" does not mean that the new system represents a radical departure from precedent. Rather, the change in Order No. 636 is simply one more adjustment, albeit a significant one, in a decades-long series of adjustments in rate design. *See, e.g., Canadian River Gas Co.*, 3 FPC 32 (1942), *aff'd, Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 65 S.Ct. 829, 89 L.Ed. 1206 (1945); *Mississippi River Fuel Corp.*, 4 FPC 340 (1945), *aff'd in part and remanded, Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433 (D.C.Cir.1947); *Atlantic Seaboard Corp.*, 11 FPC 43 (1952); *State Corp. Comm'n v. FPC*, 206 F.2d 690 (8th Cir.1953), *cert. denied*, 346 U.S. 922, 74 S.Ct. 307, 98 L.Ed. 416 (1954); *Fuels Research Council, Inc. v. FPC*, 374 F.2d 842 (7th Cir.1967); *United Gas Pipe Line Co.*, 50 FPC 1348 (1973), *reh'g denied*,

51 FPC 1014 (1974), *aff'd sub nom. Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176 (D.C.Cir.1975); *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578 (D.C.Cir.1979); *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir.1986) (*NIPSCO*).

Like past changes in rate design, FERC initiated the departure from MFV in response to changing market conditions. Specifically, the agency determined that continued adherence to MFV rate design would "inhibit the goal of the development of a competitive, national gas market and, therefore, . . . [would] not comport with the goals set forth" in Order No. 636. Order No. 636, ¶ 30,939, at 30,433. For various reasons, pipelines prior to Order No. 636 had differing amounts of fixed costs in their commodity and usage charges. As FERC determined, "[t]his situation . . . can hinder competition between gas sellers at the wellhead because competition is not based on the seller's costs and therefore on their ability to compete directly with each other." *Id.*; *see also supra* Part IV.A.1.

The PUCs' objection that FERC has used MFV pricing in the past does not come to terms with the fact that the natural gas industry is being reorganized at Congress' direction and that FERC is now attempting to structure the rate design system to favor the development of a nationwide, competitive natural gas marketplace. FERC reasonably determined that, "because in its current assessment of the prevalent economic and market circumstances it believes the goal of achieving an efficient, national gas market is the factor that should control the selection of the appropriate rate design method," Order No. 636- A, ¶ 30,950, at 30,605, its departure from the strict terms of MFV rate design as approved in 1986 was justified. Similarly, the PUCs' reliance on the practices in the oil pipeline industry is

misplaced. The same goals, problems, and solutions may or may not apply to oil pipelines,[81] but there is no requirement that rate design function in the same manner across both industries. Finally, as FERC stresses, the Order No. 636 regime permits parties to seek approval of non-SFV rate design methods in individual rate proceedings. *See* Order No. 636, ¶ 30,939, at 30,434; Order No. 636-A, ¶ 30,950, at 30,605. For all these reasons, we hold that FERC has supported its determination to abandon MFV rate design with substantial evidence in the record.

2. *FERC's choice of SFV rate design*

Several petitioners raise challenges to FERC's determination that SFV is the appropriate rate design method for the natural gas market. The LDCs argue that the commodity and usage charges under SFV rate design will not reflect differences in transportation costs for different pipelines, thus sending improper price signals to gas purchasers. The PUCs argue that under SFV rate design, pipelines will recover all of their fixed costs through reservation and demand charges and will hence have no incentive to maximize pipeline throughput. The Electric Generators argue that FERC failed to consider adequately an alternative rate design method proposed by Arizona Electric. Finally, the Small Distributors argue that the switch to SFV will result in an increase in gas prices at the wellhead, and that FERC has failed to demonstrate that such an increase is necessary to assure an adequate supply of gas. As

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81. For example, one crucial difference between rate design for oil pipelines and gas pipelines is that oil pipelines do not impose separate reservation and demand charges, thus occasioning no design problem analogous to the one the Commission confronted here. *See Association of Oil Pipe Lines v. FERC*, 83 F.3d 1424 (D.C.Cir.1996).

we noted in the previous section, our task is not to determine whether SFV is in fact the best rate design method available, but merely to determine whether FERC can support its choice with substantial evidence in the record.

a. *LDCs' claim*

The LDCs[82] claim that the switch to SFV rate design will undermine gas purchasers' ability to make economically efficient choices of gas suppliers because the per unit gas price they face from a supplier will not reflect the distance which the gas must travel over a pipeline to reach the customer. In consequence, a gas purchaser might choose to buy from supplier A, who transmits gas over pipeline AA for a distance of 1,000 miles, when the economically efficient outcome would have been for the purchaser to buy from supplier B, who transmits slightly more expensive gas over pipeline BB for a distance of only 500 miles. The LDCs' analysis, however, overlooks two important facts. First, as FERC points out, "the variable cost of transportation — basically the cost of fuel for pipeline compressors," will still be included in the commodity and usage charges. So gas purchasers will receive the proper signal regarding the actual differences among suppliers in variable transportation costs. *See* Order No. 636, ¶ 30,939, at 30,437. Furthermore, gas purchasers will still take differences in fixed transportation costs into account, because those cost components will be included in the reservation and demand charges. *Id.* As FERC notes, "[l]ocational advantages will continue to matter, because long-distance transportation generally will require more facilities, and thus will have higher fixed costs, than shorter-distance arrangements."

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82. LDCs presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co.

The LDCs argue, citing *Catalano, Inc. v. Target Sales, Inc.*, 446 U.S. 643, 648 n. 10, 100 S.Ct. 1925, 1928 n. 10, 64 L.Ed.2d 580 (1980) (*per curiam*), that FERC's removal of transportation costs from per unit charges at the supplier level amounts to "base point pricing," which, they argue, "would be [a] per se violation [ ] of the antitrust laws," if done by agreement among private parties to fix the price of transportation added to the price of products. While we have concluded that FERC's response to this argument is adequate, we further note that the base point pricing cases have involved private agreement in otherwise unregulated markets, and commodities such as cement, expensive to transport as contrasted with natural gas, a product which not only is the subject of pricing regulation but also is extraordinarily inexpensive to transport over pre-existing pipelines. *Cf. FTC v. Cement Institute*, 333 U.S. 683, 697, 68 S.Ct. 793, 801, 92 L.Ed. 1010 (1948). We accordingly reject the LDCs' challenge to FERC's decision to implement SFV rate design.

b. *PUCs' claim*

The PUCs argue that the switch to SFV rate design "will frustrate, rather than promote, the goals of maximizing efficiency and competition." Their complaint centers on the claim that because pipelines under SFV rate design will be able to collect all their fixed costs, including return on investment and taxes, in the demand charge, they will have no incentive to assure that gas actually flows through the pipeline under firm service arrangements. That is, because a pipeline will recover no fixed costs or return on investment through the commodity or usage charge, it will have no incentive to transport any gas.

FERC recognized this potential incentive problem in Order No. 636, but determined that "the pipelines will now have much

less influence on the use of their systems because they are transporting gas to, rather than selling gas at, the city-gate." Order No. 636, ¶ 30,939, at 30,436. Accordingly, "[t]ransportation volumes will mainly be a function of the needs of gas purchasers and the prices offered by gas sellers in the production areas." *Id.* In any case, "the goals to be accomplished via SFV outweigh generally the goal of allocating fixed costs to annual throughput." Order No. 636-A, ¶ 30,950, at 30,606. We find these explanations sufficiently convincing to meet the substantial evidence standard for rate design in the face of the PUCs' incentive argument.

c. *Electric Generators' claim*[83]

The Electric Generators argue that FERC failed to consider adequately the demand-responsive volumetric charge system proposed by Arizona Electric Power Cooperative, Inc. (AEPCO), as an alternative to SFV rate design. They claim that AEPCO's proposed system does a better job of rationing scarce capacity during peak demand. However, FERC correctly counters that the fact that AEPCO may have proposed a reasonable alternative to SFV rate design is not compelling. The existence of a second reasonable course of action does not invalidate an agency's determination. *See Cities of Batavia v. FERC*, 672 F.2d 64, 84 (D.C.Cir.1982) ("[T]he billing design need only be reasonable, not theoretically perfect."). Although an administrative agency must respond to "comments which, if true, . . . would require a change in an agency's proposed rule," *American Mining Congress v. EPA*, 907 F.2d 1179, 1188 (D.C.Cir.1990) (internal quotation marks and citations omitted), FERC has met that standard as to AEPCO's proposal. FERC noted the generator's concerns, but concluded that its own plan would better avoid

83. Arizona Electric Power Cooperative, Inc., sponsors this argument.

the distorting influences on the gas market experienced during MFV ratemaking. Order No. 636-A, ¶ 30,950, at 30,606-07. Though AEPCO and FERC each briefly debate the merits of the two proposals, we see no basis for voiding FERC's ruling, which appears based on substantial evidence in the record.

d. *Small Distributors' and Municipalities' claim*[84]

The Small Distributors and Municipalities argue that the effect of SFV rate design is to increase gas prices at the wellhead. They further claim that FERC failed to demonstrate that such an increase is necessary to assure adequate supply. FERC points out that this argument is not properly before the court because petitioners did not raise it in the administrative proceedings in their request for rehearing of Order No. 636. As we noted earlier, *see supra* Part IV.A.2, 15 U.S.C. § 717r(b) (NGA § 19(b)) clearly states that "[n]o objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do." *See also ASARCO*, 777 F.2d at 773-75 (elaborating on the significance of the § 717r(b) requirement that the objection be raised before FERC). Finding no mention of this price increase objection in the petitioner's rehearing request, and hearing no explanation by the petitioner of a reasonable ground for this omission, we conclude that the price increase objection is not properly before the court and decline to reach it.

3. *Regulatory Flexibility Act*

The Regulatory Flexibility Act, 5 U.S.C. §§ 601-612 (RFA), requires that an agency conduct a regulatory flexibility analysis

84. The National Association of Gas Consumers supports this argument.

(or "small entity impact analysis") for any rule that will have a "significant economic impact on a substantial number of small entities." 5 U.S.C. § 605(b). The PUCs argue that the RFA required that FERC perform a small entity impact analysis for Order No. 636 because of its significant economic effect on LDCs. However, in *Mid-Tex Elec. Co-op., Inc. v. FERC*, 773 F.2d 327, 340-43 (D.C.Cir.1985), we conducted an extensive analysis of the RFA provisions governing when a regulatory flexibility analysis is required and concluded that no analysis is necessary when an agency determines "that the rule will not have a significant economic impact on a substantial number of small entities that are subject to the requirements of the rule." *Id.* at 342 (emphasis added). FERC has no jurisdiction to regulate the local distribution of natural gas. 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply to . . . the local distribution of natural gas or to the facilities used for such distribution."). Accordingly, the allegation that Order No. 636 may have a significant economic impact on LDCs (an assertion FERC disputes) is not sufficient to trigger the mandate of the RFA. FERC had no obligation to conduct a small entity impact analysis of effects on entities which it does not regulate.

C. *FERC's Discretion to Adopt Mitigation Measures*

1. *Background*

FERC recognized that the adoption of SFV rate design could result in cost shifting among pipeline customers because of their differing load factors. Order No. 636, ¶ 30,939, at 30,435; Order No. 636-A, ¶ 30,950, at 30,601-03; Order No. 636-B, ¶ 61,272, at 62,015-16. The adoption of SFV will, at least arguably, shift costs to low load factor customers in two ways: first by removing all fixed charges from the usage charge; and second by

measuring usage solely based on peak demand, rather than annual usage. To elaborate, a low load factor customer transports most of its gas during the winter heating season; therefore, its average daily usage of its capacity entitlement is significantly below its usage on a peak day. As a result of this demand structure for low load factor customers, they usually pay proportionately more in reservation and demand fees than do high load factor customers. This result follows logically when reservation fees are constant throughout the year for a high and a low load factor customer who each have the same capacity entitlement. The low load factor customer purchases a lower annual volume of gas; hence, a larger proportion of its payments to the pipeline are made up of reservation fees. The existence of this phenomenon means that, once the pipeline has switched to SFV, the low load factor customers will pay a higher share of pipeline fixed costs than they did under MFV. Under MFV, low load factor customers could escape some of the fixed costs by not purchasing their full entitlement of gas because the per unit price of the gas contained some fixed costs. Additionally, under SFV, FERC has determined that the reservation and demand charges will no longer vary with annual usage, as they did under MFV. Order No. 636-A, ¶ 30,950, at 30,599.

To offset these cost shifts likely to result from Order No. 636, FERC adopted several mitigation measures. First, it required that pipelines "use some measure, such as seasonal contract quantities," in calculating reservation and demand fees when the switch to SFV rate design "causes significant cost shifts" to individual customers. Order No. 636-A, ¶ 30,950, at 30,599. If, even after the seasonal adjustments, the switch to SFV still resulted in a ten percent or greater rate increase under SFV for a particular customer class, FERC required that the pipeline phase in SFV rate design over four years for that

customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603-04. FERC also sought to retain the protection for small customers that the old regime offered by requiring all pipelines that offered service under a one-part volumetric rate at an imputed load factor on May 18, 1992, to offer transportation service under a similar rate structure to all customers who were eligible on that date for such an arrangement. Order No. 636-A, ¶ 30,950, at 30,600; Order No. 636-B, ¶ 61,272, at 62,018-22. We will label this mitigation measure the "small customer discount."

Petitioners bring several different challenges to the adoption of these mitigation measures and to various aspects of their implementation. We now consider each of these challenges.

2. *Justifications for mitigation measures*

The high load factor LDCs object to FERC's requirement of a small customer discount and to the use of seasonal adjustments for low load factor customers. They argue that the small customer discount results in high load factor customers having to pay higher unit charges than would be the case without the requirement. They also maintain that the use of seasonal adjustments for low load factor customers eliminates the incentive for these customers to flatten their demand over the course of the year. Seasonal adjustments also allegedly penalize high load factor customers for their foresight in using storage and other peak shaving tools in winter months to flatten their demand. The LDCs claim that the higher charges to high load factor customers resulting from these mitigation measures "unduly discriminate against residential customers of high load factor LDCs and give preferential treatment to customers" of low load factor LDCs in violation of NGA § 5(a).

FERC responds to the LDCs' claims by stressing that the effect of the mitigation measures is to preserve as much of the status quo as possible with respect to cost allocation. The intervenors point out that the LDCs' attack on the mitigation measures improperly assumes that SFV rate design is a baseline from which any mitigation measures should be judged. Both FERC and the intervenors are correct. The LDCs' claim of "discrimination" is based on the assertion that they, and ultimately their customers, will have to pay a larger share of fixed costs than they would pay without the mitigation measures. But the LDCs have no sustainable argument for why this should invalidate the measures. There is no "neutral" or inherently "fair" allocation of fixed costs, as the history of rate design amply demonstrates. The LDCs assume that allocating fixed costs according to a straight SFV methodology is the "fair" way of doing things, a curious position in light of the LDCs' opposition throughout these proceedings to the adoption of SFV rate design. But there is no "fair" baseline from which to judge a particular cost allocation scheme.

In any case, FERC correctly points out that it has long rejected the position that fixed costs should be allocated solely on the basis of peak day demand, as would apparently result under a straight SFV system with no mitigation measures. The courts have concurred in FERC's rejection of such a regime. *See NIPSCO*, 782 F.2d at 742 ("[T]he Commission long ago with judicial approval rejected the argument that fixed costs should only be allocated and recovered solely on the basis of peak day demands."). As for the LDCs' argument that the seasonal adjustments remove the incentive for low load factor customers to flatten their demand throughout the year, we note that this incentive is greatly magnified under a "pure" SFV system as compared to an MFV system. Under MFV, the low

load factor customers could have avoided part of the fixed costs during periods of low demand because part of the per unit gas charge included fixed costs. "Reducing" the stronger incentive to flatten demand that would otherwise exist under SFV is not problematic because, as we have just explained, a pure SFV system is not a proper baseline from which to judge the appropriateness of mitigation measures.

The same reasoning applies to the LDCs' claim that the mitigation measures unfairly penalize those LDCs whose foresight led them to invest in peak-shaving facilities before Order No. 636. The mitigation measures only look like an unprecedented subsidy flowing from high load factor customers to low load factor customers when one compares the Order No. 636 regime to a straight SFV regime with no mitigation measures at all. Once again, a strict SFV regime is not the proper baseline. When one compares the Order No. 636 system with the pre-Order No. 636 system, in which low load factor customers escaped part of their share of fixed costs by reducing purchases in low demand periods, the mitigation measures make sense in light of FERC's goal of avoiding sudden and shocking departures from the status quo with respect to cost allocation. In short, low load factor customers avoided some fixed costs in low demand periods before Order No. 636, and they are still avoiding some fixed costs in low demand periods after Order No. 636. LDCs which adopted peak- shaving techniques are no worse off than they were before Order No. 636. It is therefore improper to say that FERC has "penalized" them.[85]

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85. The LDCs also argue that under the Order No. 636 regime, low load factor customers have several new means of adaptation at their disposal and are not in need of mitigation measures. However, as FERC points out, none of the LDCs raised this argument in their rehearing petitions before the Commission. They are accordingly barred from raising it in this court under 15 U.S.C. § 717r(b). *See supra* Part IV.A.2.

There being no neutral standard or baseline to guide the court in evaluating mitigation measures, the only relevant question is whether FERC has made a reasonable allocation of fixed costs supported by substantial evidence. Considering the Order No. 636 series as a whole and bearing in mind FERC's regulatory goals and history, we are convinced that FERC has supported its adoption of mitigation procedures with substantial evidence. We now turn to the various challenges raised by petitioners to specific aspects of the mitigation measures.

3. *Non-permanence of mitigation measures*

As we noted above, *see supra* Part IV.C.1, FERC ordered that under certain circumstances, pipelines must phase in SFV rate design over four years for a customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603- 04. The Small Distributors and Municipalities[86] contend that, rather than phasing in new rates, FERC should have adopted permanent mitigation of their rates. They argue that "[u]nreasonable rates do not become just and reasonable by phasing them in over a four-year period. Mitigation is no less vital four years later when the Commission's four-year 'remedy' expires." But FERC responds that the purpose of the four-year phase in period was not to protect the customer class from cost shifting altogether, but merely to avoid the shock of allowing it to happen all at once. FERC's response is perfectly sensible, and we hold that the Commission has justified under the substantial evidence standard the four-year phase in period in the circumstances in which Order No. 636 requires it.

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86. Distributors joining in this argument include the American Public Gas Association and the National Association of Gas Consumers.

Appendix A

4. *Impact on pipeline rate of return*

The PUCs argue that FERC should have reduced the pipelines' rate of return because the pipelines will be able to recover all of their fixed costs and return on investment through demand and reservation charges instead of facing the uncertainty of recovering a portion of their fixed costs and return through gas sales throughout the year. *See supra* Part IV.B.2.b (describing reduced pipeline uncertainty under SFV rate design). Specifically, the PUCs contend that FERC should have followed its decision in *Transcontinental Gas Pipe Line Corp.*, 56 FERC ¶ 61,037, *modified in part*, 57 FERC ¶ 61,331 (1991), 62 FERC ¶ 61,221 (1993), 64 FERC ¶ 61,099 (1993), *rev'd in part on other grounds*, *Transcontinental Gas Pipe Line Corp. v. FERC*, 54 F.3d 893 (D.C.Cir.1995), and imposed a 25 basis point reduction in pipelines' return on equity to reflect the lower risk under SFV rate design. However, FERC stresses that it deferred any such adjustments in rates of return to the individual restructuring proceedings in light of the fact that "pipeline risk is a matter for pipeline-specific analysis in light of all risks." Order No. 636, ¶ 30,939, at 30,437. As we have said before, setting a rate of return is "an intensely practical affair requiring the conversion of inexact data into exact rates or limits upon rates." *Matson Navigation Co. v. Federal Maritime Comm'n*, 959 F.2d 1039, 1043 (D.C.Cir.1992) (citations and internal quotation marks omitted). Nothing in the law requires that FERC take a "shotgun" approach to the problem of decreased pipeline risk by ordering an across-the- board rate reduction, much less that the court do so. We note in this regard that *Transcontinental* Gas, the decision upon which petitioners rely, was itself an individual pipeline rate making decision. FERC easily meets its burden of supporting its decision to defer rate of return adjustments to individual restructuring proceedings.

5. *Individual customer vs. customer class*[87]

FERC required that pipelines use measures such as seasonal contract adjustments to avoid significant cost shifting for individual customers. If, after application of these mitigation measures, the use of SFV "still results in a 10 percent or greater increase in revenue responsibility for any historic customer class," then the pipelines are required to phase in the increase over four years. Order No. 636-B, ¶ 61,272, at 62,016 (emphasis added). The Pipeline Petitioners argue that the mitigation measures short of four-year phase in should also have been required on the basis of customer class rather than on the basis of SFV's effects on individual customers.

In deciding to base the initial mitigation measures on SFV rate design's effects on individual customers rather than customer class, FERC cited several recent decisions in individual pipeline restructuring proceedings. *Id.* at 62,016 n. 140. However, these rulings simply implement Order No. 636 and order studies on the effect of SFV rate design on individual customers, anticipating the adoption of mitigation measures on a customer-by-customer basis. But relying on these orders as a justification for the customer-by-customer basis would be a classic case of bootstrapping, amounting to a conclusion that Order No. 636 properly requires the customer-by-customer approach since several decisions implementing Order No. 636 take that approach. Nothing in any of the decisions justifies the basic determination in favor of the individual customer approach. Significantly, FERC cites no other support for its decision in Order No. 636-B to favor the individual customer approach.

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87. Williston Basin Pipeline Company seeks review of this issue.

The Pipeline Petitioners also raise an important question about the danger of the individual customer approach with respect to pipeline cost recovery:

> [R]ates are determined on the basis of costs incurred and billing quantities during a specified test period. While it is reasonable to expect that the actual billing quantities of all customers in each class during the period the rates are in effect will approximate those experienced by the class during the test period, it is likely that individual customers may experience larger variances in billing quantities. The establishment of rates on a customer-by-customer basis therefore increases the risk that a pipeline will fail to collect its total costs during the period in which rates are in effect.

Pipeline Petitioners' Brief at 27. They also argue that FERC's order fails to take into account potential customer cost reductions under Order No. 636 that are not directly related to the switch to SFV rate design, and that the individual customer method "increases the likelihood for discrimination in rates to similarly situated customers in violation of Sections 4 and 5 of the Natural Gas Act."

FERC has provided, in response to our request at oral argument, several citations to Order Nos. 636-A and 636-B which supposedly explain FERC's decision to implement the initial mitigation measures on a customer-by-customer basis. However, after examination of these citations, we conclude that the discussions cited on this question are ambiguous at best and

incomplete at worst. FERC has failed to address adequately, in either the Order No. 636 series or in its brief, the Pipeline Petitioners' objections which we have outlined above. Because, as previously noted, the Commission has failed to provide any reasoned justification for its decision on this issue, and because the petitioners' objections raise serious questions about the appropriateness of FERC's ruling, we conclude that the Commission has failed to support its decision on this issue with substantial evidence. We therefore remand to the Commission the question of whether the initial mitigation measures should be implemented on the basis of customer class for further examination.

6. *Discounts for former customers of downstream pipelines*

In requiring a continuation of the pre-Order No. 636 small customer discounts, FERC only mandated that downstream pipelines offer the discount to the class of customers eligible for it on May 18, 1992. But the Small Distributors[88] argue that FERC should have required upstream pipelines to provide the discounts to any customers of downstream pipelines who received the discounts on May 18, 1992. The downstream pipeline customers were indirect customers of the upstream pipelines under the old regime and now are direct customers of these upstream pipelines. The Small Distributors argue that these former downstream pipelines customers "are now indistinguishable from the upstream pipeline's other small customers, with whom they compete directly for markets." FERC's failure to account for this fact results in "undue discrimination between similarly-situated small customers on

88. The East Tennessee Group, the National Association of Gas Consumers, and the Tennessee Valley Municipal Gas Association support this argument.

the same pipeline solely on the basis of whether they used to be served through a downstream pipeline prior to Order [No.] 636." Although FERC did indicate in Order No. 636-B that the former downstream pipeline customers' need for discounts should be examined in individual restructuring proceedings, the Small Distributors contend that it is unfair and unreasonable to make them demonstrate such a need in restructuring proceedings when that need has already been presumed for other small customers.

The Small Distributors raise excellent points. FERC's failure to counter them with anything but its insistence that former downstream customers can raise their need for small customer discounts in upstream pipeline restructuring proceedings (perhaps they can, although the Small Distributors dispute the effectiveness of such a course of action), does not address the core of the Small Distributors' argument. FERC has made an arbitrary distinction between former indirect small customers of upstream pipelines (who are now direct small customers) and small customers who have always been direct customers of the same pipelines. Because FERC has not supported this distinction with substantial evidence in the record, we remand this issue to the Commission for further consideration of whether or not the small customer benefits should be made available to the former downstream small customers.

7. *Triennial rate review*

In Order No. 636-A, FERC abandoned the requirement of triennial rate review, which it had formerly imposed on many pipelines in exchange for granting the pipelines certain powers over their rates. FERC explained that the only reason it had formerly required triennial rate review was because of the power it had granted the pipelines. Specifically, under the purchased

gas adjustment (PGA) regulatory scheme, participating pipelines had discretion to change the gas supply cost element of their rates. In exchange for this ability, "pipelines had to agree to a reexamination of all their costs and rates at three year intervals to assure that gas cost increases were not offset by decreases in other costs." Order No. 636-A, ¶ 30,950, at 30,671; *see also* 18 C.F.R. § 154.303(e) (laying out triennial rate review requirement). Under the Order No. 636 regime, pipelines have no special rate adjustment mechanism comparable to the PGA scheme, so FERC concluded that triennial rate review was unnecessary. In Order No. 636-B, FERC even raised the question of whether it had the discretion to order triennial rate review under the Order No. 636 regime, noting that "there are limits to the authority of the Commission to require pipelines to periodically justify their existing rate levels." Order No. 636-B, ¶ 61,272, at 62,044-45 (citing *Public Serv. Comm'n v. FERC*, 866 F.2d 487 (D.C.Cir.1989) (*PSCNY*) (holding that requiring periodic filings under NGA § 4 is beyond FERC's statutory authority)).

The LDCs[89] argue that FERC should not have abandoned triennial rate review. First, they claim that FERC "ignored that the market- based sales rate authority granted pipelines under Order [No.] 636 is a 'special rate adjustment mechanism' " justifying a periodic rate review. In any case, they argue that FERC certainly does have the authority to impose triennial rate review under the Order No. 636 regime. In their view, PSCNY simply means that "FERC cannot impose [a periodic filing] requirement except as a condition of some other benefit

89. Associated Gas Distributors, Consolidated Edison Company of New York, Inc., Illinois Power Co., and Peoples Natural Gas Co. present this argument. Supporting intervenors are PECO Energy Co. and Washington Gas Light Co.

voluntarily accepted by the pipeline." Because Order No. 636 conferred several benefits on pipelines, the LDCs contend that FERC's failure to attach periodic rate review to at least one of those benefits was unjustified. FERC, however, contends that the "benefits" to pipelines cited by the LDCs are not nearly so certain: "there is no reason to believe that by allowing a pipeline to sell gas at market-based rates, rather than regulated cost-based rates, Order No. 636 makes it more likely that rates for unbundled transportation service will become unjust and unreasonable."

The PUCs also argue in favor of retaining triennial rate review, restating the LDCs' argument that FERC has conferred a benefit on pipelines by instituting SFV rate design and can accordingly require periodic rate review. They also point out that, under SFV, as long as fixed costs continue to decline, pipelines will have no incentive to file NGA § 4 rate cases since they will be recovering all of their fixed costs through reservation and usage fees. Consumers will then be left with an NGA § 5 complaint as their only option for protecting themselves, but a § 5 complaint is less satisfactory than a § 4 rate case because under § 5 the burden is on the complainant to establish the unjustness or unreasonableness of the rate. Also, § 5 relief is prospective only; § 4 relief can encompass a refund order. FERC responds that "traditional ratemaking tools are available to take account of long-run declining costs, and a three-year review [is] unnecessary."

FERC's position that it lacks authority to impose triennial rate review is quite strong. The LDCs' claim that the market-based sales authority granted to pipelines is a "benefit" to which triennial rate review may be attached rings hollow in light of the fact that pipelines are leaving the gas sales business in favor

of gas transportation under Order No. 636. Furthermore, whatever the benefits of SFV rate design to pipelines, they are not benefits voluntarily accepted by the pipelines and so cannot be the basis for the imposition of periodic rate review. *See PSCNY*, 866 F.2d at 492 (noting that FERC's authority to impose triennial rate review in the PGA context "obviously rests on pipeline consent" to triennial rate review in exchange for automatic PGA adjustment authority). In any case, in the presence of these serious doubts about FERC's authority to impose periodic rate review in the Order No. 636 context and in view of the alternative procedures available to the Commission for ensuring reasonable rates, we hold that petitioners have failed to show that FERC has not supported its decision to drop triennial rate review with substantial evidence.

V. Transition Costs

In this part of the opinion, we briefly review the history behind the transition cost issue and consider each of the petitioners' challenges to FERC's treatment of transition costs.

A. *Background to Transition Costs*

1. *Order No. 436 and its successors*

Order No. 436 began the natural gas pipeline industry's transition from its historic role as gas merchant to gas transporter. The Order authorized interstate gas pipelines to convert to blanket-certificated "open-access" transportation service. *See supra* Part I.B. In exchange, however, customers of those pipelines that did convert were permitted both (1) to convert their firm sales obligations into firm transportation contracts and also (2) to reduce their obligations to purchase gas from the

pipelines. Pipeline customers in large numbers exercised their right under the Order to buy less gas from the pipelines, and secured gas supplies from less expensive sources. The pipelines themselves were then left with massive obligations to purchase high-priced gas at the wellhead:

> [T]he conditions under which the NGPA began to relax wellhead price controls — namely acute gas shortage and sharply rising prices for alternative fuels — tended to divert pipeline attention from the hazards of incurring long-term obligations to buy high-priced gas. Under pressure from the Commission, the pipelines had typically purchased gas under contracts for very long terms. Besides incorporating high prices (and provisions for escalation upward), the contracts commonly included "take-or-pay" provisions, requiring the pipeline to pay for some specified percentage, say 75%, of the deliverable gas even if it took less. While usually subject to recoupment later, and while a perfectly natural allocation of risk between producer and purchaser, the take-or-pay provisions effectively committed the pipelines to high gas costs in what by 1982 proved to be a time of falling prices, both for competing fuels and for substitute supplies of gas not covered by contract.

AGD I, 824 F.2d at 995-96 (citations omitted) (emphasis added).

Thus arose the "take-or-pay" liabilities addressed by the

Commission in Order No. 436 and its successors, as well as by this court in a variety of opinions. *See supra* Part I.B. Specifically, because most customers could purchase gas more cheaply from other sources, pipelines essentially were unable to pass through the costs of their own supply obligations. With purchases sharply reduced, pipelines owed massive "take-or-pay" liabilities to gas producers, which they had to either "buydown" — *i.e.*, reduce — or "buyout" — *i.e.*, eliminate. In Order No. 436, the Commission refused to set a general policy on whether or how pipelines could attempt to recover these costs. We vacated and remanded the Order, concluding that, in this regard, it was not based on reasoned decisionmaking, primarily because it appeared to grossly underestimate the financial impact of take-or-pay liability on pipelines. *Id.* at 1021- 30. Of great concern to the court was the likelihood that even higher gas prices would simply cause more customers to switch suppliers, thereby exacerbating the take-or-pay crisis. This cycle of ever increasing prices and ever shrinking customer base — a phenomenon that petitioners label the "death spiral" — made it very unlikely that the pipelines would in fact recoup their take-or-pay liabilities absent some mechanism for separately passing those costs through to their customers.

In subsequent proceedings, the Commission adopted and this court approved various measures designed to address that concern and allow pipelines to pass through some of their take-or-pay liabilities to a broader range of customers. *See supra* Part I.B. Most pertinent to our analysis here, under Commission policy, a pipeline could agree to absorb between 25% and 50% of its take-or-pay costs in exchange for the right to bill customers an equal share through a fixed charge, and recover the remaining amount through a volumetric surcharge based on total throughput. Customers, and in turn the consuming public,

ultimately reimbursed pipelines for approximately $6.4 billion in take-or-pay costs, while the pipelines themselves absorbed $3.6 billion.

2. *Order No. 636 and petitioners' challenges*

After Order No. 436, all of the major interstate pipelines converted to open-access transportation. Not all customers on those pipelines, however, exercised their right to unbundle their sales agreements and reduce their gas purchase obligations. Several years later in Order No. 636, the Commission mandated unbundling and authorized sales customers to reduce their pipeline gas purchases. When customers exercised that right and secured gas supplies from other sources, the pipelines once again incurred substantial take-or-pay liabilities; though the Commission labeled these liabilities "gas supply realignment costs" in Order No. 636, they arose from the same type of producer- pipeline contract provisions as the "take-or-pay" costs considered in Order No. 436. *Cf.* Order No. 636-A, ¶ 30,950, at 30,649 n.466 ("Any costs that would qualify for recovery as GSR costs could be filed for recovery under [the successor to Order No. 436,] Order No. 528.").

In allocating recovery of GSR costs, however, the Commission adopted a policy more advantageous to the pipelines. Instead of refusing to establish a mechanism for pipelines to recover their take-or-pay costs, as it originally had in Order No. 436, FERC authorized pipelines to bill their customers separately for 100% of their GSR costs. This policy was, in fact, a substantial change from even Order No. 500, which permitted pipelines to surcharge their transportation customers for take-or-pay costs only if they agreed to absorb between 25 and 50% of those costs. The Commission set forth

the mechanisms available to pipelines under Order No. 636 as follows:

> . . . The Commission will permit pipelines full cost recovery of prudently incurred gas supply realignment costs deemed to be eligible under this rule. To recover those costs, a pipeline will be permitted to use either a negotiated exit fee, or a reservation fee surcharge recoverable from Part 284 firm transportation customers.
>
> Under this rule, a firm entitlement holder has options as to how to react to gas supply realignment costs: it may remain a sales customer of the pipeline; otherwise, it may take an assignment of the pipeline's existing contracts or pay an exit fee/reservation fee surcharge for costs approved by the Commission.

Order No. 636, ¶ 30,939, at 30,458. On rehearing, FERC modified this ruling somewhat, and required pipelines to bill 10% of their GSR costs to interruptible transportation customers. *See infra* Part V.E.3.b.2.

Pipelines also face three other types of significant transition costs under Order No. 636: (1) unrecovered gas costs or credits remaining in the purchased gas adjustment (PGA) account when a pipeline terminates its PGA mechanism; (2) costs of pipeline assets (such as storage facilities) currently used to provide bundled sales service which are not directly assignable to customers of the unbundled services ("stranded costs"); and (3)

costs for equipment required to physically implement the rule ("new facility costs"). Order No. 636, ¶ 30,939, at 30,457. FERC determined in Order No. 636 that pipelines would generally be allowed to recover 100% of these costs. *Id.* at 30,457-60.

Petitioners raise several challenges to FERC's treatment of transition costs. First, they claim that FERC erred in allowing pipelines to recover 100% of their stranded costs, arguing that such recovery violates applicable legal standards. Second, they contend that FERC failed to adequately address the problem of "LDC bypass," which occurs when large industrial customers bypass LDCs, thereby avoiding transition costs properly attributable to them. Third, they oppose Order No. 636's passthrough of above-market prices paid by pipelines for synthetic natural gas from the Great Plains Gasification Plant. Finally, they challenge in several respects FERC's treatment of GSR costs.

B. *Stranded Costs and the "Used and Useful" Doctrine*

A separate class of Order No. 636 transition costs are "stranded costs," which are those "incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services." Order No. 636, ¶ 30,939, at 30,460. To be denominated "stranded," an investment (1) must have been prudently made, Order No. 636-A, ¶ 30,950, at 30,662, but (2) must be no longer "used and useful" after Order No. 636, Order No. 636-B, ¶ 61,272, at 62,041. Examples include upstream pipeline capacity for which a downstream pipeline cannot find a buyer, and storage capacity that a pipeline no longer needs when the volume of its sales service shrinks. Order No. 636, ¶ 30,939, at 30,460. According to the Commission, pipelines can recover their stranded costs

in NGA § 4 rate filings. *Id.*; *see also* Order No. 636-B, ¶ 30,950, at 62,042 ("The Commission will allow pipelines to make limited section 4 filings to recover . . . the costs of stranded facilities that are currently incrementally priced . . . . However, pipelines must file to recover the costs of most, if not all other stranded facilities in general section 4 rate proceedings.").

The PUCs challenge the Commission's ruling, *see* Order No. 636-B, ¶ 61,272, at 62,041, that pipelines may recover 100% of their stranded costs. Their presentation is straightforward: items that are not currently "used and useful" may not be included in a utility's rates. In support, the PUCs invoke the Commission's statement in *New England Power Co.*, 42 F.E.R.C. ¶ 61,016, at 61,078 (1988), that "[i]n general, the used and useful standard provides that an asset may be included in a utility's rate base only when the item is used and useful in providing service." They also cite to this Court's statement in *Tennessee Gas Pipeline v. FERC*, 606 F.2d 1094, 1109 (D.C.Cir.1979), that "the precept endures that an item may be included in a rate base only when it is 'used and useful' in providing service."

In its brief, the Commission replies along two fronts. First, it contends that the PUCs' objection is premature, given that in Order No. 636, the Commission stated that, in subsequent restructuring proceedings, it would "consider arguments about whether particular facilities are used and useful, or whether the costs should be recoverable as transition costs" in § 4 rate proceedings. Order No. 636-A, ¶ 30,950, at 30,662. Second, the Commission contends that the "used and useful" principle invoked by the PUCs, while generally sound, does not apply to facilities that have been stranded only because of the Commission's own action. In other words, the pipelines should recover on their investments as they would have had Order No. 636 never been promulgated.

While we ultimately affirm the position taken by the Commission in the administrative proceedings, we believe that both the PUCs and the Commission itself may have overlooked a relevant distinction on appeal: the difference between a utility's rates and its rate base. "The rate allowed a utility is the sum of (1) its cost of service, and (2) its rate base multiplied by its rate of return." *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1172 (D.C.Cir.1987) (en banc). "Generally, the rate base is comprised of total capital invested in facilities minus depreciation plus cash working capital. The rate of return, on the other hand, is a weighted average of different rates applied to debt, preferred stock and common stock." *Id.* at 1203 (Mikva, J., dissenting). "Calculation of rate base is a critical step in establishing maximum rates, since the product of rate base multiplied by allowed rate of return is the total sum of money the agency allows to investors in the firm." RICHARD J. PIERCE, JR. & ERNEST GELLHORN, REGULATED INDUSTRIES 102 (3d ed. 1994).

The cases cited by the PUCs, and not challenged by the Commission, stand for the proposition that the items in a utility's rate base generally should currently be used and useful to consumers. As a result, investors generally profit only from those investments that presently benefit consumers. However, that principle does not answer the question whether investments that are not used and useful may nonetheless be included in the utility's rates, *i.e.*, still treated as part of the utility's cost of service.[90]

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90. Our opinion should not be read to prohibit the Commission from applying the "used and useful" principle to issues of recovery through cost of service. Instead, as we explain in our discussion, infra at 117, of *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333 (D.C.Cir.1981), this Court has recognized that the Commission is not required to do so in all instances.

Viewed in this light, the general statement in Order No. 636 that pipelines will recover 100% of their stranded costs still leaves the Commission with a number of options in the § 4 rate proceedings. For example, the Commission could decide that stranded costs should merely be included in the pipeline's cost of service, recoverable through amortization over time. In such an instance, "FERC has already moved somewhat in the direction of balancing competing interests by permitting recovery of the costs of building the plant in the cost of service. Investor interests have not, therefore, been entirely ignored." *Jersey Central*, 810 F.2d at 1192 (Starr, J., concurring). The Commission might also allow the pipeline to recover not only the amortization, but also interest, *i.e.*, the "cost" of the unamortized portion of the investment. The Commission could further decide to include stranded investments in the utility's rate base and thereby generate a profit for investors.

In the administrative proceedings, the Commission assiduously avoided announcing a general standard that would control the manner in which stranded costs may be recovered. Thus, Order No. 636, at 30,460 (emphasis added), states that while "most of the costs of new facilities would be includable in rate base, . . . there is no way of anticipating the nature and amount of the stranded costs, and thus no way at this time of devising an appropriate billing mechanism on a generic basis." Similarly, in Order No. 636-B, ¶ 61,272, at 30,662, the Commission deferred until individual rate cases a party's objection that "costs associated with physical plant that is no longer used and useful . . . should . . . no longer be includable in the rate base."

The PUCs' objection therefore is ripe for review only to the extent that they contend that pipelines should not recover

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100% of their Order No. 636 stranded costs in any fashion. We cannot at this point address the specific question of whether pipelines should be permitted to include stranded costs in their rate base, and thereby receive a profit on the investment, because Order No. 636 adopted no such rule. *Accord, e.g., Columbia Gas Trans. Corp.*, 64 F.E.R.C. ¶ 61,060 (1993) (deferring determination of rate base treatment of stranded cost recovery to § 4 proceeding); *National Fuel Gas Supply Corp.*, 63 F.E.R.C. ¶ 61,291 (1993) (same). In fact, in at least one NGA section 4 rate proceeding, the Commission expressly refused to permit such treatment of stranded costs, explaining:

> Included in [the pipeline's] claim for stranded cost treatment for the production facilities, is a pretax return allowance on the unamortized balance. . . . As discussed above, in order for [the pipeline] to receive stranded cost treatment for these facilities, they must no longer be used and useful. It is long standing Commission policy that when facilities are not used and useful, they do not qualify for rate base treatment. In addition, the recovery of stranded costs is designed to compensate pipelines for out-of-pocket costs that they have no other means of recovering. While the costs of facilities are out-of-pocket costs, equity return and related income taxes are not. Therefore, [the pipeline] should not be allowed a pretax return allowance on the unamortized balance. The Commission will limit [the pipeline's] recovery to interest on the unamortized amount . . . .

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> This is consistent with the way the Commission has treated other costs of a transitional nature that are being amortized over a period of years to reduce the rate impact on customers, *e.g.*, GSR cost amortizations or take-or-pay buyout and buydown cost amortizations. The interest treatment prescribed above adequately compensates the pipeline for the time value of the outstanding unamortized balance, but recognizes the nature of the costs being amortized.

Equitrans, Inc., 64 F.E.R.C. ¶ 61,374, at 63,601 (1993); *cf. National Fuel Gas Supply Corp.*, 71 F.E.R.C. ¶ 61,031, at 61,138 (1995) ("A rate of return on the amount of written down facilities would be inappropriate since this allows a return on facilities that are not economically viable, and may also result in a competitive advantage for the pipeline. The pipeline would, however, be allowed to recover interest on the unamortized portion of its written-down plant over a reasonable amortization period, as this will keep the pipeline whole for the direct cost of its investment in the facilities.").

We reject the PUCs' claim (now properly limited to the argument that the "used and useful" principle per se prohibits pipeline recovery of stranded costs even when merely amortized as part of the cost of service), because it was previously rejected in *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333 (D.C.Cir.1981) (*NEPCO*). In *NEPCO*, we considered "whether FERC's refusal to include project expenditures in the rate base, while allowing their recovery as costs over time, is a valid approach to allocating the risks of project cancellation."

We found such an approach acceptable because, in that case, the Commission's decision was based on substantial evidence and had adequately balanced the interests of investors and ratepayers. *Id.*; *see also Jersey Central*, 810 F.2d at 1183 (rejecting claim that *NEPCO* adopted per se bar to including in rate base items not currently "used and useful"). So long as the Commission's decisionmaking in the individual § 4 proceedings satisfies that standard, it will survive any subsequent challenge brought on "used and useful" grounds.

C. *LDC Bypasses*

Order No. 636 creates new opportunities for large retail customers to bypass LDCs and connect directly to pipelines. Problems of scale and efficiency preclude other customers from taking advantage of such options, however. State regulators and LDCs argued before FERC that it is unfair to force an LDC's remaining customers to pay the transition costs that they contend are fairly allocatable to the departed customers of the LDC. Order No. 636, ¶ 30,939, at 30,461; Order No. 636-A, ¶ 30,950, at 30,658-59. FERC, however, refused to adopt a generic rule to address this problem, determining instead that it would consider requests for relief on a case-by-case basis. The Commission believes that it is reasonable to require that "an LDC seeking relief in a bypass situation . . . show that there is a direct nexus between the bypass and the pipeline, so that the costs it seeks to avoid should be reallocated to the bypassing customer." Order No. 636-A, ¶ 30,950, at 30,659.

The PUCs protest that the burden placed on LDCs of demonstrating the nexus between the bypass and the pipeline is "nearly impossible to meet" because of its specificity. They accordingly argue that the pipeline and the bypassing customer

should have to explain why they shouldn't bear the bypassing customer's share of transition costs. FERC counters that it has "made no statement as to the ultimate burden of proof in such situations" but has left resolution of LDC bypass claims to individual proceedings. However, as noted above, FERC did find it "fair" to require an LDC seeking bypass relief to show a "direct nexus between the bypass and the pipeline." While arguably it may not constitute a "burden of proof" in a technical sense, it does constitute a hurdle of causation which LDCs seeking relief must clear in individual proceedings. Therefore, in contrast to the Intervenors' argument, FERC's "direct nexus" requirement is ripe for review.

We find the PUCs' arguments unpersuasive. First, we note that the "burden" LDCs face in these cases is not "impossible to meet." As FERC notes, it has already made it clear that at least one bypassing customer still must bear its fair share of GSR costs. *See Arcadian Corp. v. Southern Natural Gas Co.*, 67 FERC ¶ 61,176, at 61,538 (1994). Second, FERC reasonably determined that the factual circumstances surrounding LDC bypasses "differ sufficiently that the Commission cannot justify a generic rule [apart from the "direct nexus" requirement] that would be appropriate in all circumstances." Order No. 636-A, ¶ 30,950, at 30,659. We accordingly reject the PUCs' challenges on this issue.

D. *Above-Market Recovery for Great Plains Gas*

The Great Plains Gasification Plant was constructed to convert coal into synthetic natural gas (SNG). In Order No. 636-A, FERC noted that in *Transcontinental Gas Pipe Line Corp.*, 55 FERC ¶ 61,446, *reh'g denied*, 57 FERC ¶ 61,345 (1991) (*Transco*), it had "approved a settlement that provided for a

volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to Transco's obligations to purchase synthetic gas from Great Plains." Order No. 636-A, ¶ 30,950, at 30, 657-58. Several petitioners complained that this arrangement was in substantial conflict with the competition-enhancing purposes of Order No. 636. FERC admitted as much in Order No. 636-A, but determined that the volumetric surcharge "is consistent with the Commission's goal of providing a smooth transition from the prior regulatory environment to the new market-oriented environment." *Id.* at 30,658. Furthermore, FERC followed its reasoning in Transco, concluding that "it is 'reasonable for all [the pipeline's] customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users . . . by increasing the supply of available gas.' " *Id.*

The PUCs challenge FERC's treatment of Great Plains gas, contending that it "conflicts with the goal which forms the heart of Order [No.] 636 — providing consumer access to competitively priced supply." They also cite Commissioner Langdon's partial dissent in Order No. 636, in which he stated that "every comma, word, sentence and paragraph of the order is internally inconsistent" with respect to *Great Plains gas*. Order No. 636, ¶ 30,939, at 30,472 (Langdon, C., concurring in part and dissenting in part). "I fail to see how the [volumetric surcharge] will ultimately benefit the consumer, or transmit accurate pricing signals." *Id.* The PUCs also claim that FERC's decision requires gas consumers to subsidize Great Plains, an outcome the Commission has previously rejected with respect to failed SNG plants.

FERC responds to the PUCs' claims by arguing that

Elizabethtown III, 10 F.3d at 873-74, has already settled this issue. *Elizabethtown III* reviewed FERC's orders approving restructuring agreements between Transco and its customers. The petitioners challenged Transco's passthrough of its above-market cost of SNG from Great Plains on the basis that "customers should pay rates based only upon the costs they cause the pipeline to incur." *Id.* at 873. We rejected that argument, however, concluding that the departure from cost-causation principles was justified because, "had the Great Plains plant succeeded in increasing the supply of natural gas, it would have contributed also to reducing the price of natural gas, to the benefit of all natural gas consumers." *Id.* at 874.

The PUCs argue that *Elizabethtown III* is inapposite because it did not consider the treatment of *Great Plains gas* in a restructuring proceeding in light of the overall purposes of Order No. 636. Although the PUCs are correct that *Elizabethtown III* does not address *Great Plains gas* in light of Order No. 636, we note that the case was both argued (February 23, 1993) and decided (December 17, 1993) after the issuance of Order No. 636 (April 16, 1992), Order No. 636-A (August 12, 1992), Order No. 636-B (November 27, 1992), and even Order No. 636-C (January 8, 1993). The *Elizabethtown III* court thus had ample opportunity to consider the consistency of the *Great Plains* volumetric surcharge with the overall policy objectives of the Order No. 636 regime. Petitioners point to no developments since the *Elizabethtown III* decision that effectively distinguish that case from the issue before us, and we are accordingly constrained by *Elizabethtown III*'s treatment of the Great Plains issue. We therefore reject petitioners' challenges to FERC's treatment of Great Plains gas.

Appendix A

E. *GSR Costs*

In this part of the opinion, we consider petitioners' challenges to the GSR costs that arose from the modification of producer-pipeline contracts. Order No. 636 both (1) required pipelines to unbundle their firm sales contracts into separate transportation and gas sales arrangements and (2) permitted customers to reduce or eliminate their obligations to buy gas from pipelines under the sales component. The pipelines, with fewer sales customers, were in turn forced by market pressures to buy their way out of many costly supply contracts with gas producers, thereby incurring some $1.7 billion in "gas supply realignment (GSR) costs." In Order No. 636, the Commission authorized pipelines to recover 100% of their prudently incurred GSR costs from their blanket-certificated transportation customers.[91]

Petitioners raise several objections to this recovery policy, all of which we conclude are ripe for review. First, they argue that FERC should have used its NGA § 5 authority to require gas producers to bear part of the GSR costs. We conclude that FERC reasonably declined to exercise the limited authority it possessed over producer-pipeline contracts. Second, petitioners contend that the Commission erred in its assignment of GSR costs to two classes of pipeline transportation customers. By and large, we conclude that the Commission's allocation of GSR costs among customers was an acceptable application of "cost

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91. In Order No. 636-B, ¶ 61,272, at 52,040-41, the Commission suggested that those pipelines that offered discounted transportation services might not be permitted 100% recovery, a statement that the pipelines challenged in this proceeding. The Commission has since withdrawn that suggestion, however, *Natural Gas Pipeline Co. of Am.*, 69 FERC ¶ 61,029, at 61,116-17 (1994), rendering the pipelines' claim moot.

spreading" and "value of service" principles. We do conclude, however, that the Commission has failed to explain adequately its decision in all instances to allocate 10% of GSR costs to the pipelines' interruptible transportation customers. Third, petitioners contend that the pipelines themselves should have been required to absorb some portion of their GSR costs. After carefully reviewing the issue, we conclude that the Commission did not engage in reasoned decisionmaking such that we can sustain its decision to exempt the pipelines altogether. We do not hold that the Commission was required to assign a particular portion of GSR costs to pipelines, however, but instead remand this question (along with the 10% interruptible transportation figure) for further consideration.

1. *Ripeness of petitioners' challenges to FERC's treatment of GSR transition costs*

"Settled principles of ripeness require that [a court] postpone review of administrative decisions where (1) delay would permit better review of the issues while (2) causing no significant hardship to the parties." *Northern Indiana Public Service Co. v. FERC*, 954 F.2d 736, 738 (D.C.Cir.1992) (*NIPSCO*). FERC argues that none of the petitioners' challenges to its allocation of GSR costs are ripe for review. It notes that, under Order No. 636, "a pipeline may file . . . to recover GSR costs only after it has restructured its system in full compliance with the rule" and argues that disputes over GSR cost recovery are therefore better left to individual restructuring proceedings. *See* Order No. 636, ¶ 30,939, at 30,460; Order No. 636-B, ¶ 61,272, at 62,042. Additionally, FERC noted in Order No. 636-B that the Order No. 636 series transition cost policies "are not incorporated in the regulations, but are policy statements." Order No. 636-B, ¶ 61,272, at 62,034-35. It further explained that it

would "review specific proposals for recovering transition costs with reference to the particular circumstances of each pipeline system and the degree of support those proposals enjoy from the affected parties." *Id.*; *see also* Order No. 636-A, ¶ 30,950, at 30,648-49 ("Guidelines and policies will be developed . . . in concrete cases" to address concerns about GSR cost recovery.). FERC thus compares this case to AGA I, 888 F.2d 136, which held unripe challenges to Order No. 500's equitable sharing policy in light of the strong norm against reviewing policy statements and other tentative agency positions where no hardship will result to the parties.

The problem with FERC's ripeness argument is that it fails to meet NIPSCO's two criteria for declaring a case unripe. The Commission claims that it intended in the Order No. 636 series to merely announce a general policy approach to GSR costs and leave analysis of specific GSR cost disputes to individual pipeline restructuring proceedings. "Where the language and context of [an agency] statement are inconclusive, we have turned to the agency's actual applications." *Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682 (D.C.Cir.1991). In this case, FERC's treatment of the GSR cost issue in subsequent proceedings is inconsistent with a general policy approach. For example, in restructuring proceedings for Texas Eastern Transmission Corporation, petitioners challenged FERC's allocation of GSR costs, but FERC determined that "[b]ecause the Commission has addressed all of the Industrial Groups' arguments in Order No. 636 et seq., the Industrial Groups' request for rehearing is denied." *Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,100, at 61,512 (1993). In Texas Eastern's NGA § 4 filing for the recovery of GSR costs, FERC again refused to consider these arguments. *See Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,254, at 63,245-46 (1993). In *Columbia Gas Transmission*

Corp., 64 FERC ¶ 61,365, at 63,588 (1993), FERC refused to consider certain GSR cost arguments because they were "essentially a request for rehearing of Order No. 636. There is no need to revisit these arguments again. We deny rehearing." In *ANR Pipeline Co.*, 64 FERC ¶ 61,140, at 62,083-84 (1993), FERC rejected arguments about GSR costs "for the same reasons stated in Order No. 636-B."

Unlike the situation in *Papago Tribal Utility Authority v. FERC*, 628 F.2d 235, 240 (D.C.Cir.1980), where we found that FERC might "resolve the claims of the parties and obviate any injury to them if we allow it to complete its proceedings," FERC has demonstrated that it does not plan to offer any significant justifications for its treatment of GSR costs as outlined in the Order No. 636 series other than those presented in the Order No. 636 series itself. We therefore hold that FERC's treatment of GSR costs does not constitute an unreviewable general "policy statement" but rather a final determination ripe for judicial review. Because FERC continually relies on the Order No. 636 series' treatment of GSR costs, it is not reasonable to conclude that a delay in review would permit better review of the issue.

The second part of the NIPSCO test asks whether delay in review would cause significant hardship to the parties. Put another way, the petitioners must show "a direct and immediate effect on their primary conduct." *Tenneco Gas v. FERC*, 969 F.2d 1187, 1211 (D.C.Cir.1992). FERC admits that Order No. 636 GSR costs as of February 7, 1996, totaled almost $1.7 billion without interest, hardly an insignificant amount. In any case, it is unlikely that FERC would have gone to such lengths to assure that pipelines recover 100% of GSR costs if those costs were unlikely to have an immediate effect on the conduct of the parties having to pay them. Furthermore, to the extent that pipelines

and gas producers continue to renegotiate contracts, such negotiations will undoubtedly be affected by FERC's treatment of GSR costs in the Order No. 636 series (and in the individual restructuring proceedings). We accordingly conclude that FERC's treatment of GSR costs causes "a direct and immediate effect" on the petitioners' primary conduct, and that the petitioners' claims are ripe for review.

2. *Gas producers' exemption from GSR costs*

In the Order No. 636 series proceedings, petitioners presented several alternative solutions to the transition cost problems, some of which would have required that FERC abrogate existing contractual obligations between pipelines and gas producers. These alternative solutions would have forced gas producers to bear part of the transition costs. FERC declined to adopt these proposals on the grounds that, among other things, it lacked § 5 authority to abrogate producer-pipeline contracts. Order No. 636-A, ¶ 30,950, at 30,643. The Commission is correct that it lacks such authority. We have already said as much in *AGA II*, 912 F.2d at 1505, where we concluded that Congress unambiguously restricted FERC's § 5 powers to jurisdictional contracts. And FERC's jurisdiction over wellhead contracts began to decline as soon as Congress eliminated such jurisdiction over new wellhead contracts. *See NGPA* § 601(a)(1)(A), (B), 15 U.S.C. § 3431(a)(1) (A), (B); *Pennzoil Co. v. FERC*, 645 F.2d 360, 380 (5th Cir.1981). The PUCs' claims that FERC's authority to regulate pipeline rates for the benefit of consumers gives it implicit authority over nonjurisdictional contracts crumble against the wall of the *AGA II* holding.

The PUCs also argue that, even if *AGA II* applies, FERC still retained jurisdiction over some "old" gas contracts when it

issued Order No. 636 and that it should have used its § 5 authority to reform those contracts. (In AGA II we recognized that FERC still had jurisdiction over some wellhead contracts, noting that "[t]he proportion of wellhead sales that is subject to FERC jurisdiction steadily declines . . . as old gas is exhausted." *AGA II*, 912 F.2d at 1505.) But exercising such jurisdiction would have conflicted with Congress' clear intent that FERC get out of the business of regulating wellhead gas prices, making such an approach a questionable vehicle for addressing the petitioners' concerns. Furthermore, as FERC noted in Order No. 636-A, its jurisdiction "over most producer/pipeline supply contracts has already been removed under the NGPA. As of January 1, 1993, there will be no remaining vestiges of such jurisdiction by virtue of the Decontrol Act." Order No. 636- A, ¶ 30,950, at 30,643 n.460. In light of these concerns, it would be unreasonable to conclude that FERC should have reformed any producer-pipeline contracts to force producers to bear part of the GSR costs. We accordingly decline to accept the petitioners' invitation to remand this issue to the Commission.

3. *Allocation of GSR costs among customer classes*

Order No. 636 authorizes pipelines to recover their GSR costs from all of their blanket-certificated transportation customers. Petitioners contend that the Commission erred in allocating costs to two specific classes of customers: customers that were not directly responsible for GSR costs under Order No. 636 (*i.e.*, those that did not reduce their pipeline gas purchases in response to mandatory unbundling); and interruptible transportation customers. FERC defends its allocation of GSR costs based on the principles of "cost spreading" and "value of service." It is there that we begin.

Appendix A

a. *"Cost spreading" and "value of service"*

Order No. 500, the immediate successor to Order No. 436, authorized pipelines to recover take-or-pay costs from both their customers that were blanket certificated under the Commission's open-access regime and customers that were individually certificated under NGA § 7(c). The § 7(c) shippers objected that they were merely transportation customers of pipelines, and were therefore not in any way responsible for the fact that the pipelines, in preparing to accommodate their anticipated sales obligations, had incurred take-or-pay liabilities. According to the § 7(c) shippers, the Commission's allocation of take-or-pay costs therefore violated accepted principles of "cost causation," under which "[p]roperly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer," *Alabama Electric Coop. v. FERC*, 684 F.2d 20, 27 (D.C.Cir.1982) (citation and internal quotation marks omitted).

The Commission conceded that its take-or-pay allocation could not be sustained under a narrow view of cost causation. It argued, however, that "circumstances surrounding the take-or-pay crisis and the transformation of the pipeline industry necessitate and justify the crafting of new ratemaking principles." *K N Energy v. FERC*, 968 F.2d 1295, 1301 (D.C.Cir.1992). Specifically, the Commission defended its policy on grounds of "cost spreading" and "value of service":

> Under this first notion, allocating take-or-pay costs to transportation customers who admittedly may not have directly caused them is acceptable because, in the

> Commission's judgment, the extraordinary nature of this problem requires the aid of the entire industry to solve it; there are no other alternatives that would allow a transition to a market-based pipeline industry to be effectuated. Closely related to this rationale is FERC's second: namely that all segments of the industry — including those who may not have caused take-or-pay problems — will nonetheless ultimately benefit from their resolution and the concomitant move toward an open access regime; consequently, all segments can rightly be assessed a portion of take-or-pay costs.

Id.

In *K N Energy*, we sustained the Commission's invocation of "cost spreading" and "value of service," *id.* at 1302, though we made clear that our approval of those principles was limited, *see id.* ("A more searching inquiry may well prove necessary . . . if the Commission should attempt to adopt these ratemaking rationales outside the take-or-pay context."). We did not, however, approve of the Commission's conclusion that application of "cost spreading" and "value of service" justified billing take-or-pay costs to § 7(c) customers. While the Commission contended that § 7(c) customers benefitted from Order Nos. 436 and 500 through lower transportation rates, the data before the court suggested that those rates had in fact increased. *Id.* Moreover, the Commission's Orders allocated costs to pipelines' remaining sales customers inconsistently. *Id.* at 1303. We therefore remanded for further consideration of the

manner in which take-or-pay liabilities should be applied to § 7(c) customers.[92]

In this case, the Commission contends that its assignment of GSR costs to all blanket-certificated shippers was an appropriate application of "cost spreading" and "value of service" principles.

b. *Petitioners' challenges*

1.) *Limitation to bundled sales customers*

The Industrial End-Users object to FERC's decision to allow recovery of transition costs from all blanket-certificated transportation customers, including those that were not pipeline sales customers at the time of the implementation of Order No. 636. The ground for their objection is straightforward: GSR costs arose from the contracts between the pipelines and those firm sales customers that they retained after Order No. 436, not from contracts with customers that had previously converted under Order No. 436. Specifically, Order No. 636 required firm sales customers to convert their sales entitlements into firm transportation entitlements. Some of those customers also exercised their option to reduce their pipeline gas purchases, leaving the pipelines with excess sales capacity, purchase obligations, and related costs:

> Indeed, nearly 65 percent of pipeline capacity was committed to sales customers prior to Order 636 even though pipelines' sales accounted for less than 20% of deliveries by

92. On remand, the Commission concluded that the application of take-or-pay costs to § 7(c) customers was not justified. *Williston Basin.*

> 1991. Transportation customers who had earlier converted under Order 436 and 500 from sales service to transportation service, or who had never been pipeline sales customers, had already negotiated their gas supply arrangements and had previously paid the cost of restructuring prior to Order 636. Significantly, nothing in Order 636 permits these transportation customers to reform their supply or transportation arrangements (or to pass on to others the associated costs).

Industrial End-Users' Br. at 18 (emphasis in original). The contracts of non-sales customers therefore did not directly give rise to Order No. 636 GSR costs.[93] The Industrial End-Users further note that even if customers that had previously converted to firm transportation service benefit from Order No. 636, the Commission made no attempt to correlate the degree of that benefit with its cost allocation decisions.[94]

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93. The same is true of § 7(c) individually certificated shippers, which FERC exempted from paying GSR costs under Order No. 636. The Industrial End-Users maintain that exempting § 7(c) shippers but including all Part 284 shippers is arbitrary. As is discussed in Part III.C.1, *supra*, however, FERC excluded § 7(c) shippers both from the capacity release program and from paying transition costs in order to equitably spread both the costs and benefits of Order No. 636.

94. The Small Distributors and Municipalities briefly make the separate argument that the Commission's allocation of GSR costs constitutes unlawful "retroactive ratemaking." They contend that "many small customers had converted to transportation prior to July 31, 1991 [the date of issuance for the Order No. 636 Notice of Proposed Rulemaking] and were therefore not on notice that they would be held responsible for such pipeline gas supply

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FERC's approach in Order No. 636, however, is valid under the value-of-service and cost-spreading rationales approved by this court in the *K N Energy* decision. Even those customers not directly responsible for GSR costs benefit from the availability of lower priced transportation in the unbundled marketplace. Moreover, the Commission's options in spreading out costs to pre-Order No. 636 firm sales customers are substantially limited by the filed rate doctrine and the bar to retroactive ratemaking; FERC simply cannot reach backwards through time in a truly equitable manner. While the Industrial End- Users correctly note that to date we have approved the Commission's departure from traditional cost-causation principles in only limited circumstances, those circumstances are squarely presented in this case. GSR costs under Order No. 636 are the functional equivalent of take-or-pay costs under Order No. 436, and "the Commission has not betrayed its obligations to the NGA or precedent by employing these ratemaking principles in its attempt to bring closure to the take-or-pay drama," *K N Energy*, 968 F.2d at 1302.

2.) *Interruptible transportation customers*

The Industrial End-Users challenge the Commission's decision to allocate 10% of a pipeline's GSR costs to interruptible transportation customers.[95] They contend that

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costs when taking transportation service prior to that date." Those customers, however, were on notice as of July 31, 1991 that if they continued to receive open-access transportation services, they would be responsible for paying GSR costs that arose after that date. *See* Notice of Proposed Rulemaking, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 32,480, at 32,560 (1991).

95. While the Commission suggests that in the restructuring proceedings

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unbundling confers no real benefit on that class of customers, who therefore should not be responsible for paying GSR costs. They further contend that interruptible transportation customers in fact may receive inferior service after Order No. 636 because the higher volume of firm transportation expected to result under the Commission's capacity release program may displace interruptible transportation services. Moreover, given that less gas is transported by interruptible than firm transportation, the GSR surcharges applied to interruptible transportation in some cases may exceed those charges applied to firm transportation.

The Small Distributors and Municipalities concur that FERC should have better spread the costs of restructuring throughout the industry, but take the contrary position that additional costs should have been allocated to interruptible transportation. Invoking "benefit of service" principles,[96] the brunt of their claim is a relatively complex economic analysis of why interruptible transportation customers stand to gain a great deal under Order No. 636. In sum, their theory is that the customers who receive the most benefit under Order No. 636 are those with elastic demands, *i.e.*, those most likely to use interruptible transportation.

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it may consider the manner in which the 10% is collected, it apparently does not consider the 10% figure itself open to negotiation. In three cases, the Commission has required the allocation of 10% of GSR costs to interruptible transportation cases based expressly on the ruling in Order No. 636-A. *See Texas Gas Transmission Corp.*, 68 F.E.R.C. ¶ 61,118, at 61,594 (1994); *Florida Gas Transmission Co.*, 63 F.E.R.C. ¶ 61,160, at 62,079, 1993 WL 308439 (1993); *Southern Natural Gas Co.*, 62 F.E.R.C. ¶ 61,136, at 61,946 (1993).

96. The Small Distributors and Municipalities also contend that under the same principles GSR costs should be allocated to gas producers. This point is discussed above, *see supra* Part V.E.2.

Our concerns here mirror those in our review of the application of take-or-pay costs to § 7(c) customers in *K N Energy*. The fact that interruptible transportation customers are part of the "natural gas industry" is not, standing alone, sufficient to assign them GSR costs; even the "cost spreading" and "value of service" principles that we have approved allow for the imposition of costs only upon those entities that either bear some responsibility for the costs or derive some benefit from the solution imposed. *See K N Energy*, 968 F.2d at 1302-04. We are quite sensitive to the Commission's expert conclusion that interruptible transportation customers do derive benefits from unbundling under Order No. 636; an active market for firm transportation would seem likely to drive down the cost of less desirable interruptible transportation, and while the additional use of firm transportation under Order No. 636 may crowd out some interruptible transportation, that results at least in part from customers converting from interruptible to firm service. Moreover, unlike our review of Order No. 500, we are not presented in this case with evidence that the Commission's prediction of reduced costs was wrong as a factual matter. Further still, interruptible transportation customers do clearly benefit from Order No. 636 through access to low cost transportation that is available through the Commission's capacity release mechanism.

More troubling, however, is the Commission's apparently stringent adherence to the 10% figure in all instances. FERC elected to allocate GSR costs to interruptible transportation (IT) in response to claims by some pipelines that they would not be able to recover all of their transition costs from firm customers alone. It completely failed, however, to explain why it chose 10% rather than 5% or 15%, and why that 10% figure should be applied to every pipeline; the Orders and FERC's brief simply

do not attempt to defend that figure whatsoever. For example, we are presented with absolutely no explanation of why IT should contribute 10% of GSR costs even on those pipelines on which IT constitutes less than 10% of throughput. And, while the Commission correctly points out that courts have recognized the inherent ambiguities in ratemaking, that does not immunize an agency from engaging in reasoned decisionmaking that is susceptible of appellate review. As we explained in reviewing Order No. 500:

> While we owe the Commission substantial deference in matters predictive and economic, we cannot ignore the Commission's unwillingness to address an important challenge to its stated benefit rationale for charging transportation customers. It most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it — that it conduct a process of reasoned decisionmaking. The deference we owe FERC's expert judgment does not strip us of that responsibility. Indeed, . . . we will uphold an agency's decision "if, but only if, we can discern a reasoned path from the facts and considerations before the [agency] to the decision it reached."

Id. at 1303 (citations omitted) (second emphasis added).

In this instance, we cannot discern the Commission's path from its view that interruptible transportation customers should bear some of the burden for GSR costs to the conclusion that

the share should be 10%. *Cf.* WALT WHITMAN, LEAVES OF GRASS, Darest Thou Now O Soul ("Darest thou now O soul, Walk out with me toward the unknown region, Where neither ground is for the feet nor any path to follow?"). And, while we are sympathetic to the Commission's view that "[t]he task of determining fair allocations of transition costs is ultimately thankless, even though [it] bring[s] all [its] experience and best judgment to bear on it," Order No. 636-B, ¶ 61,272, at 62,034, the law requires more than simple guesswork.[97] We therefore remand the issue to the Commission for further consideration.

4. *Pipelines' exemption from GSR costs*

To this point, petitioners' objections to the distribution of GSR costs have involved the allocation of those costs among groups of pipeline transportation customers. As a separate matter, petitioners forcefully contend that the Commission erred in not requiring the pipelines themselves to absorb any GSR costs. They note the remarkable similarities between Order No. 636 GSR costs and Order No. 436 take-or-pay costs, and contend that the pipelines should absorb GSR costs just as they do take-or-pay costs. While we do not conclude that the Commission necessarily was required to assign the pipelines responsibility for some portion of their GSR costs, we do agree with petitioners that the Commission's stated reasons for exempting the pipelines do not rise to the level of "reasoned decisionmaking." We therefore remand the issue to the Commission for further consideration.

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97. In point of fact, there may be unique circumstances in which it is simply impossible to attribute costs with anything resembling mathematical accuracy. In such instances, however, the Commission still must take the time to explain why that is the case.

Initially, we agree with petitioners that the Commission's stated rationale for allocating take-or-pay costs to pipelines substantially applies in the context of GSR costs as well. As we explained above, *see supra* Part V.A, take-or-pay and GSR costs both arise from the same provisions in producer-pipeline contracts and result from pipelines' former firm sales customers reducing their gas purchases. We therefore find it instructive that in the take-or-pay context, the Commission itself concluded that pipelines should bear some of the burden, reasoning that

> allowing a pipeline to recover 100 percent of its settlement costs through a fixed charge would be inconsistent with the Commission's holding in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problem.

Order No. 500-H, ¶ 30,867, at 31,575. In Order No. 636 as well, the Commission acknowledged that GSR costs had arisen at least in part due to the conduct of the pipelines, characterizing bundled sales arrangements, which arose in substantial part from pipelines' market power, as an unreasonable and unlawful restraint of trade. Order No. 636, ¶ 30,939, at 30,405. Moreover, according to the Commission, the pipelines benefit from Order No. 636, in that they "will presumably receive more favorable prices or other valuable consideration resulting from contract reformation." Order No. 636-A, ¶ 30,950, at 30,643; *cf. id.* at 30,642 ("[Petitioners] generally allege that since Order No. 636 will benefit all segments of the gas industry, all segments should bear the costs. The Commission believes that the benefits of Order No. 636 indeed will be widespread.").

The Commission nevertheless puts forward a wide variety of arguments for exempting pipelines from paying GSR costs, which we will address on the merits seriatim. We begin, however, by noting that, as a general matter, the Commission's arguments seem directed toward proving the wrong point. FERC allocated Order No. 636 GSR costs to customers based on the principles of "cost spreading" and "value of service" discussed above, *see supra* Part V.E.3.a. When it exempted the pipelines from those costs, however, the Commission reverted to traditional concepts of "cost causation," or to use its characterization, "returned to first principles holding that a utility is entitled to the opportunity to recover all of its prudently incurred costs in providing public service."[98] It is important to emphasize that these are competing models for allocating the industry's costs of service. "Cost causation" correlates costs with those customers for whom a service is rendered or a cost is incurred. For example, as we noted above, *see supra* Part V.E.3.b.1, the Industrial End-Users argue that under a cost causation model, the only customers who should be required to pay GSR costs are those that reduced their pipeline gas purchases in response to Order No. 636. "Cost spreading" and "value of service," in contrast, take a much wider view, assigning the costs of service to those classes of industry participants that either are at fault for the take-or-pay dilemma or benefit from its resolution. Applying these latter principles, we sustained the Commission's determination that GSR costs should be paid by all blanket-certificated transportation customers, even those that did not directly cause the pipelines

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98. Of course, there may be a world of difference between what the Commission views as pipelines' legal entitlement to recover GSR costs by charging their remaining sales customers higher prices and the pipelines' economic ability to do so in the marketplace. *See supra* at 115 (discussing possibility of pipelines' "death spiral" of higher prices and smaller customer base).

to incur liabilities under their supply contracts. *See supra* Part V.E.3.b.1.

If the Commission intends to assign GSR costs according to these "cost spreading" and "value of service" principles, it must do so consistently or explain the rationale for proceeding in another manner.[99] We approved the invocation of those principles in *K N Energy* because FERC had concluded that the take-or-pay crisis could be resolved only by spreading costs throughout the "entire industry," 968 F.2d at 1301 (emphasis added), and because we recognized that "all segments of the industry . . . will benefit," *id.* (emphasis added), from restructuring. *Cf.* Order No. 636-A, ¶ 30,950, at 30,650 ("[I]n the Commission's judgment, [Order No. 636] continues the general goal of spreading the costs of industry restructuring.").[100] The Commission therefore cannot, without explanation, burden blanket-certificated transportation customers on the ground that they will benefit from Order No. 636, and then ignore that same factor as it relates to the pipelines. For example, the fact that both pipelines and customers will benefit from expanded open-access transportation is one argument in favor of applying GSR costs to both. On the other hand, it is not particularly relevant

99. For example, the Commission may conclude that responsibility for GSR costs would cause such harm to a particular segment of the industry as to raise substantial concerns about its economic health. In this case, FERC contended that it exempted pipelines from paying GSR costs because of the pipelines' precarious financial position. The Commission never articulated that rationale in the proceedings below, however, and we therefore do not consider it. *See Burlington Truck Lines v. United States*, 371 U.S. 156, 168-69, 83 S.Ct. 239, 245-46, 9 L.Ed.2d 207 (1962). The issue remains open for further consideration on remand.

100. This applies, of course, only to those entities over which the Commission may lawfully exercise jurisdiction. *See supra* Part III.B.

that GSR costs will total only approximately $1.7 billion, while take-or-pay costs were $10 billion, for that proves nothing about the relative responsibility of various segments of the industry for those costs. On the same footing is the Commission's recognition that pipelines have already paid $3.6 billion in take-or-pay costs; petitioners are quite right when they note that consumers have in the end paid nearly twice that amount. The relevant question is instead whether the $3.6 billion dollar figure should be even larger — recognizing that the figure for consumers is sure to grow — because the pipelines are in part responsible for GSR costs and will benefit from Order No. 636.

This is not to say, however, that it is impossible, or even improbable, that the Commission on remand can establish a convincing rationale for exempting the pipelines. For example, arguably, the pipelines' contribution to the costs of theindustry's transition has already been so disproportionately large vis-a-vis consumers that they are entitled to be excused from further responsibility. It also may be that unbundling under Order No. 636 benefits consumers so much more than it does the pipelines that the pipelines should bear few or no GSR costs. Such issues, however, require a fuller airing in the administrative proceedings on remand than is evident from the record developed in the initial go-round.

Two final arguments raised by the Commission merit separate attention. First, it notes that unbundling under Order No. 436 was voluntary while under Order No. 636 it is mandatory. It is unclear in the Order No. 636 series, however, how the "voluntariness" of the reduction in pipeline gas purchases correlates with the pipelines' responsibility for the resulting costs. The fact that certain pipelines made an economic choice to convert to open-access transportation and thereby

almost certainly incur take-or-pay costs under Order No. 436 does not make other pipelines less responsible for the same type of costs when the Commission ultimately decided that it had to force the final stages of industry restructuring. Moreover, we rejected that very distinction when we vacated Order No. 436:

> FERC also alludes to the "voluntary" character of pipeline provision of Order No. 436 transportation. There are two flaws in this. First, refusal of the option may spell bankruptcy: inability to provide blanket-certificate transportation for fuel-switchable users may in current market circumstances cause critical load loss . . . .
>
> Second, the argument obscures distinctions between pipelines in the aggregate and alone. To be sure, Order No. 436 gives pipelines an option, blanket-certificate transportation, which . . . is not available outside of Order No. 436. But as soon as a single pipeline finds it attractive enough to accept, each competing pipeline will come under competitive pressure to match the first's flexibility.

AGD I, 824 F.2d at 1024.

The Commission also notes that under Order No. 500, but not Order No. 636, those pipelines that paid take-or-pay costs received a heightened presumption that those liabilities were prudently incurred.[101] As with "voluntariness," however, the

101. Order No. 636 subjects GSR charges to the same form of prudence (Cont'd)

Appendix A

Order No. 636 series does not explain how the presumption of prudence correlates with FERC's cost-spreading and value-of-service rationales. The Orders' differing treatment of prudence stems from the fact that Order No. 500 and its successors allowed pipelines to recover some, but not all, of their take-or-pay liabilities through a fixed charge on transportation if and only if they absorbed some of those costs themselves. The presumption of prudence created an incentive for the pipelines to engage in cost absorption in that it reduced expenses they might later incur in litigating the appropriateness of their take-or-pay liabilities. Order No. 636 needs no such incentive because pipelines can directly bill transportation customers for 100% of GSR costs, an option that was never available under Order No. 500. And,

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(Cont'd)

review generally applied to pipeline billings. Thus, customers have the burden of proving any claim they might press that particular GSR charges were not prudently incurred. Order No. 636-B, ¶ 61,272, at 62,039. Petitioners challenge the Commission's conclusion that "the possibility of having to defend the incurrence of [GSR] costs, and suffer disallowance of recovery, should provide sufficient incentive for pipeline diligence in minimizing these costs," Order No. 636, ¶ 30,939, at 30,461. Prudence review, however, is a well-settled practice, and petitioners have offered no particular reason for disallowing its use in this context. In point of fact, petitioners' complaint in large part seems to be that the Commission's application of its prudence standards is too lax, not that the use of prudence review is per se unlawful. *See id.* at 26 (citing *Columbia Gas Trans. Corp.*, 26 F.E.R.C. ¶ 61,034, on reh'g, 26 F.E.R.C. ¶ 61,334 (1984); *Texas Gas Trans. Corp.*, 48 F.E.R.C. ¶ 61,266 (1986), as examples of inadequate prudence review). We do not foreclose such claims from being raised in any petition for review of a ruling by the Commission that a pipeline's GSR costs were prudently incurred. The same holds true for petitioners' claim that the Commission will fail to distinguish correctly between Order No. 636 GSR costs and charges that pipelines should properly recover as Order No. 436 take-or-pay costs. We may review the question when properly presented with a ruling by the Commission on particular GSR costs.

of course, were the Commission on remand to assign some proportion of GSR costs to pipelines, it could apply the same presumption of prudence that it used in the take-or-pay context.

In sum, we cannot conclude from the record now before us that the Commission's decision to exempt pipelines completely from paying GSR costs was the product of reasoned decisionmaking. Order No. 636 is based on principles of cost spreading and value of service that are, in turn, premised on the notion that all aspects of the natural gas industry must contribute to the transition to an unbundled marketplace. In addressing pipelines' liability for GSR costs, however, the Commission at the very least undervalued those considerations. We leave it to the Commission on remand to consider whether the pipelines should nonetheless continue to be exempted from such costs in light of the factors we have identified.

F. *Conclusion*

With respect to stranded costs, we hold that FERC's interpretation of the used and useful doctrine is supported by substantial evidence. We reject petitioners' argument that FERC inadequately addressed the LDC bypass issue, and we also reject petitioners' challenges to the volumetric surcharge for above-market Great Plains gas.

Turning to GSR costs, we first conclude that petitioners' challenges are ripe for review. Next, we hold that FERC did not err by failing to exercise its NGA § 5 authority so as to force gas producers to bear part of the transition costs. Furthermore, we sustain the Commission's application of GSR costs to the full range of blanket-certificated transportation customers. We remand the case to the Commission, however, for further

consideration of the appropriate share of those costs to be paid by interruptible transportation customers and the gas pipelines.

VI. Conclusion

In its broad contours and in most of its specifics, we uphold Order No. 636. However, we remand certain aspects of Order No. 636, which we now recount, to the Commission for further explanation. With regard to no-notice transportation service, we remand for the Commission to explain why it restricted entitlement to receive no-notice service to those customers who received bundled firm-sales service on May 18, 1992. We remand the right-of-first-refusal mechanism for the Commission to explain why it adopted a twenty-year term-matching cap. Two aspects of the SFV mitigation measures require further explanation: first, the decision to require initial mitigation measures, such as seasonal contract adjustments, on the basis of the effect of switching to SFV on individual customers, whereas the four-year phase-in mitigation measure is determined by the effect on customer classes; and second, the decision that former customers of downstream pipelines are ineligible for small-customer rates. Finally, with regard to the recovery of GSR costs, we remand for an explanation of why, in light of the equitable- sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636, pipelines can pass through all their GSR costs to customers, and also for an explanation of why the Commission decided, in allocating costs among customers, that interruptible-transportation customers should bear 10% of GSR costs.

Until the Commission takes final action on remand, however, we leave these measures in place as currently formulated. *See A.L. Pharma, Inc. v. Shalala*, 62 F.3d 1484, 1492

(D.C.Cir.1995); *Checkosky v. SEC*, 23 F.3d 452, 462-65 (D.C.Cir.1994) (opinion of Silberman, J.); *cf. AGA I*, 888 F.2d at 153 (stating that the Commission must promptly provide a reasoned explanation).

It is so ordered.

APPENDIX B — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636", F.E.R.C. STATS. & REGS. (CCH) ¶ 30,939 (1992)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-000

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-065

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Before Commissioners: Martin L. Allday, Chairman;
Charles A. Trabandt,
Elizabeth Anne Moler,
Jerry J. Langdon and Branko Terzic.

ORDER NO. 636

FINAL RULE

(Issued April 8, 1992)

Appendix B

I. INTRODUCTION

By adopting the proposed rule with modifications, this rule requires significant alterations in the structure of interstate natural gas pipeline services in light of the changes in the natural gas industry brought about by the Natural Gas Policy Act of 1978 (NGPA),[1] the Commission's open access transportation program,[2] and the Natural Gas Wellhead Decontrol Act of 1989 (Decontrol Act).[3] The Commission believes that this rule, when fully implemented, will finalize the structural changes in the Commission's regulation of the natural gas industry. This rule will therefore reflect and finally complete the evolution to competition in the natural gas industry initiated by those changes[4] so that all natural gas suppliers, including the pipeline

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1. 15 U.S.C. 3301-3432 (1988).

2. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,665 (1985), *vacated and remanded*, Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988), *readopted on an interim basis*, Order No. 500, 52 FR 30334 (Aug. 14, 1987), FERC Stats. & Regs. [Regulations Preambles, 1986-1990] ¶ 30,761 (1987), *remanded*, American Gas Association v. FERC, 888 F.2d 136 (D.C. Cir. 1989), *readopted*, Order No. 500-H, 54 FR 52344 (Dec. 21, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 (1989), *reh'g granted in part and denied in part*, Order No. 500-I, 55 FR 6605 (Feb. 26, 1990), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,880 (1990), *aff'd in part and remanded in part*, American Gas Association v. FERC, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991).

3. Pub L. No. 101-60, 103 Stat. 157 (1989).

4. Those changes are discussed in detail, *infra*.

as merchant, will compete for gas purchasers on an equal footing. As discussed below, this promotion of competition among gas suppliers will benefit all gas consumers and the nation by "ensur[ing] an adequate and reliable supply of [clean and abundant] natural gas at the lowest reasonable price."[5]

II. PUBLIC REPORTING REQUIREMENTS

The Commission estimates the public reporting burden as a result of this rule to be an average of 4,810 hours per response for FERC-545, 2.7 hours for FERC-549 and 9.94 hours for FERC-592. The annual reporting burden associated with this rule is estimated to be 428,090 hours for FERC-545, 410 hours for FERC-549, and 885.2 hours for FERC-592 for a total of 429,385.2 hours. The estimate includes time for reviewing the requirements adopted by this rule, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information and filing this information with the Commission. Most of the burden hours (428,090 hours under FERC-545) are related to a one-time implementation tariff filing requirement. Interested persons may send comments regarding these burden estimates or other aspects of these collections of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, DC 20426 [Attention: Michael Miller, (202) 208-1415]; and to the Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

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5. S. Rep. No. 39, 101st Cong., 1st Sess., at p. 1 (1989) and H.R. Rep. No. 29, 101st Cong., 1st Sess., at p. 2 (1989).

III. THE COMMISSION'S GOALS IN ADOPTING THIS RULE

The Commission's responsibility under the Natural Gas Act (NGA)[6] is to protect the consumers of natural gas from the exercise of monopoly power by pipelines[7] in order to ensure consumers "access to an adequate supply of gas at a reasonable price."[8] This mission must be undertaken by balancing the interests of the investors in the pipeline, to be compensated for the risks they have assumed, and the interests of consumers,[9] and in the light of current economic, regulatory, and market realities. Hence, the Commission must fulfill its NGA mandate in the context of the decontrolled gas commodity market, the competition among gas merchants (including pipelines) for gas sales to local distribution companies (LDCs) and end users, such as industrials and gas-fired electric generators, and continued pipeline market power over transportation. In addition, the Commission's goal here is informed by Congress' urging, when it enacted the Decontrol Act, that the Commission "improve [the]

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6. 15 U.S.C. 717-717w (1988).

7. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.").

8. Tejas Power Corp. v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

9. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). ("The rate-making process under the [NGA] . . . involves a balancing of the investor and consumer interests.").

competitive structure [of the natural gas industry] in order to maximize the benefits of [wellhead] decontrol."[10]

At the same time, the Commission recognizes that the natural gas industry has undergone significant changes in the past ten years. Historically, pipelines have served as gas merchants — buying gas at the wellhead and selling it at the city gate to LDCs. This bundled sales service was reliable and suited the regulatory and commercial situation then prevailing in the gas industry. Indeed, until recently, there was little, if any, competition between gas suppliers in the natural gas industry.

The Commission has recognized the movement to competition set in motion by the NGPA in 1978. From the special marketing programs in 1984, to the elimination of pipeline minimum bills, to Order Nos. 436 and 500, the Commission has sought to promote and expand access to the wellhead market. Now, the complete deregulation of the wellhead market is on the horizon. The Commission must, therefore, take further steps to ensure that the public can realize the full benefits of the competition at the wellhead.

Since the issuance of Order No. 436, the Commission's efforts to adopt a more competitive gas market have been hindered. Non-pipeline sellers have correctly argued that the transportation of their gas supplies is not comparable to the transportation embedded in a pipeline's sales service, particularly during peak periods. This hinders their ability to sell gas on a long-term basis. On the other hand, pipelines have argued that existing transportation service cannot be improved since they must retain capacity to meet LDCs' existing

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10. H.R. Rep. No. 29, *supra*, at p. 6.

certificated sales levels and fulfill their NGA section 7(c) service obligations. At the same time LDCs have argued that they cannot convert existing certificated firm sales service to transportation because that transportation may not be as reliable as existing pipeline bundled sales service during peak periods. In addition, LDCs have been concerned that transportation capacity will be abandoned at the end of the contract term, should they convert from firm sales to firm transportation.

This rule addresses all of those issues. First, the Commission is taking steps to equalize the transportation of gas sold by pipelines and nonpipeline sellers. Second, the Commission is providing a means to recover all of the costs of restructuring existing non-market sensitive gas supply contracts. Finally, the Commission is providing for a "no-notice" transportation service in response to those who have expressed a particular concern about reliability during peak periods. In addition, the Commission is responding to concerns about pregranted abandonment for transportation services at the end of the contract term.

The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system — a natural monopoly — does not give a competitive advantage to pipelines over other sellers in the sale of natural gas. This will ensure that the benefits of decontrol redound to the consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act.[11]

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11. "Repeal of the remaining wellhead controls will promote the (Cont'd)

Appendix B

The Commission's primary aim in adopting the instant regulations is to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service. The Commission will do this by regulating pipelines as merchants and as open access transporters in a manner that accomplishes two fundamental goals. The first goal is to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible. As the House Committee Report to the Decontrol Act stated: "All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies."[12]

The Commission's second fundamental goal is to accomplish the first goal in a way that continues to ensure consumers "access to an adequate supply of gas at a reasonable price."[13] The Commission will act in a way that harmonizes both goals and thereby promotes competition and protects gas consumers. The Commission's intent is to further "facilitat[e] the unimpeded operation of market forces to stimulate the production of natural gas . . . [and thereby] contribute to reducing our Nation's dependence upon imported oil, help to ensure the

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(Cont'd)

unimpeded transmission of market signals from burnertip to wellhead and thereby help to ensure adequate supplies of reasonably priced natural gas in the future." S. Rep. No. 39, *supra*, at p. 2.

12. H.R. Rep. No. 29, *supra*, at p. 6.

13. Tejas, *supra*, at 1003; H.R. Rep. No. 29, *supra*, at p. 2.

availability of clean-burning natural gas for purposes of addressing environmental problems and the need for electric generating capacity[.]"[14]

The Commission believes that to accomplish those objectives it is vital to give all gas purchasers (LDCs and end users, such as industrials and gas-fired electric generators) the ability to make market-driven choices about the price of gas as a commodity and about the cost of delivering the gas. Simply put, efficiency in the now national gas market can be realized only when the purchasers of a commodity know, in a timely manner, the prices of the distinct elements associated with the full range of services needed to purchase and then deliver gas from the wellhead to the burnertip. Only then will gas purchasers be able to purchase, based upon their needs, the exact services they want with full recognition of the prices that they would have to pay. And only then will the Commission be assured that all gas is transported to the market place on fair terms. What best serves the interests of gas purchasers — the ability to make informed choices — is also important for gas sellers. Nonpipeline sellers also need to know the prices of the distinct elements of pipeline services in order to price their product and to decide the exact pipeline services needed to bring their gas to market. This rule provides both gas purchasers and gas sellers with the ability to make the necessary informed choices.

The Commission is adopting the major elements of the proposed rule, as modified below. In brief, this rule requires pipelines to unbundle (*i.e.*, separate) their sales services from their transportation services at an upstream point near the production area and to provide all transportation services on a

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14. S. Rep. No. 39, *supra*, at p. 2.

basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier. This rule issues blanket sales certificates to pipelines so that they can offer unbundled firm and interruptible sales services at market-based rates. In addition, pipelines will be required to provide a variety of transportation services to their shippers. This includes a new unbundled "no-notice", firm transportation service, firm transportation service that is unbundled and improved in quality, unbundled storage services, and interruptible transportation services, among others. As stated above, this will permit gas purchasers and gas sellers to choose the exact transportation service that they want, including a combination of services that will ensure that the pipelines can deliver an adequate supply of gas to the city gate from various sources when that supply is needed.

This rule also amends Section 284.221(d) of the Commission's Regulations[15] in further response to the remand of the United States Court of Appeals for the District of Columbia Circuit in *American Gas Association v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (*AGA II*).[16] The amendment to Section 284.221(d) would allow pregranted abandonment for interruptible and short-term (one year or less) firm transportation, and for long term (over one year) firm transportation under certain conditions. In addition, this rule adopts the straight fixed variable method for rate design,

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15. 18 CFR 284.221(d).

16. As discussed below, on February 13, 1991, the Commission's initial response to the AGA II remand was to issue an order staying in part Section 284.221(d). Natural Gas Pipelines After Partial Wellhead Decontrol, 56 FR 6962 (Feb. 21, 1991); III FERC Stats. & Regs. ¶ 30,915 (Feb. 13, 1991) (Order No. 500-J).

unless the Commission provides otherwise. Finally, this restructuring rule modifies the terms of existing capacity brokering programs to conform to a generic capacity releasing program that incorporates many features of capacity brokering while addressing concerns about the discriminatory allocation of pipeline capacity.

IV. BACKGROUND

A brief history of the natural gas industry and its regulation puts the instant rulemaking in historical perspective, and shows that the rule is a logical outgrowth of the changes in both the industry and its regulation as they have evolved over the last fifty plus years.

In 1938, Congress enacted the NGA to regulate the sale for resale in interstate commerce of natural gas.[17] Congress' action stemmed from the Supreme Court's barring of state regulation of wholesales of natural gas[18] and from a 1935 report of the Federal Trade Commission (FTC).[19] The FTC report specifically referred to the "[u]nregulated control of pipe-line transmission and of wholesale distribution" as a "positive evil."[20] The FTC report described the significance of control over the pipelines as follows:

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17. 15 U.S.C. 717-717w (1988).

18. *See, e.g.*, Peoples Natural Gas Co. v. Public Service Commission of Pennsylvania, 270 U.S. 550 (1926).

19. Final Report of the Federal Trade Commission to the Senate of the United States pursuant to S. Res. 83, 70th Cong., 1st Sess. (1935).

20. *Id.* at 615.

Appendix B

> Whoever controls the channels by which a product is marketed controls the market so far as the supply is concerned. Concentrated control of those channels confers a strategic advantage that may be used by those possessing it to extend their domination into both the producing and distributing branches of the industry.[21]

In that light, Congress enacted the NGA because it "considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas."[22] Congress' "primary aim . . . was to protect consumers against exploitation at the hands of natural gas companies"[23] to ensure consumers "access to an adequate supply of gas at a reasonable price."[24] Congress, therefore, regulated the interstate chain of distribution of natural gas from the wellhead to market under a public utility model.[25] The "heart of the new regulatory system" was the "fixing of 'just and reasonable' rates"[26] for

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21. *Id.* at 591.

22. FPC v. Texaco, Inc., 417 U.S. 380, 397-398 (1974).

23. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944).

24. Tejas, *supra*, at 1003.

25. Mobil Oil Corp. v. FPC, 417 U.S. 283, 302-03 n.23 (1974).

26. FPC v. Hope Natural Gas Co., 320 U.S. 591, 611 (1944).

natural gas companies (both producers and pipelines) engaging in the sale for resale in interstate commerce of natural gas.[27] The structure of the natural gas industry regulated by the NGA was simple. The producers would sell their natural gas in the production area to the interstate pipelines at Commission-determined just and reasonable rates. The pipelines would transport their purchased gas and their own production to the city gate for sale to local distribution companies (LDCs) at Commission-determined just and reasonable rates which recovered both the pipelines' cost of gas and cost of transmission. In addition, the pipelines would sell gas to end users in nonjurisdictional sales with an appropriate allocation of costs to the nonjurisdictional services.[28] Producer sales to LDCs or end users in the production area, with the pipeline providing only the transportation, were rare. The central features of the NGA-regulated natural gas industry were Commission-determined just and reasonable prices and interstate pipeline sales of gas for resale to LDCs at the city gate at those prices in transactions that combined or bundled into one package the pipelines' gas supply and transmission costs.

The interstate natural gas shortages of the 1970s were the catalyst for reform of the regulation of the natural gas industry. Simply put, the Commission's struggles with producer rates did not prove adequate to the task of ensuring an adequate supply

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27. In Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), the Supreme Court held that the just and reasonable rate prescription of the NGA applied to the rates of gas producers. See also the discussion of producer regulation under the NGA in Public Service Commission of the State of New York v. Mid-Louisiana Gas Co., 463 U.S. 319, 327-331 (1983).

28. *See, e.g.*, Colorado Interstate Gas Co. v. FPC, 324 U.S. 581 (1945).

of interstate gas.[29] Hence, Congress responded to the natural gas shortages by enacting the NGPA to increase the flow of gas into the interstate market.

The NGPA created new statutory rates for the wholesale gas market, for so-called "first sales" of natural gas, in lieu of rates established by the Commission. Those new rates were "intended to provide investors with adequate incentives to develop new sources of supply."[30]

As part of the new rate structure, the NGPA also started the process of decontrolling wellhead prices of natural gas. Upon decontrol, NGPA Section 601 removed much of the pricing of the nation's natural gas supplies from the Commission's regulatory jurisdiction.[31] In addition, the NGPA, in Section 311, broke down the existing barriers between intrastate and interstate markets for natural gas. In that vein, Congress took action to promote gas transportation by interstate and intrastate pipelines by authorizing the Commission to approve certain transportation

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29. *See* Public Service Commission of the State of New York v. Mid-Louisiana Gas Co., 463 U.S. 319, 330-31 (1983). Commission established prices for gas in the interstate market could not compete with prices available in the intrastate markets where the prices were not regulated.

30. *Id.* at 334. In the NGPA, Congress eliminated this distinction between the interstate and intrastate gas markets.

31. *See* Pennzoil Co. v. FERC, 645 F.2d 360, 380-383 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); Associated Gas Distributors v. FERC, 824 F.2d 981, 1001 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988); *See also* Order No. 500-H, *supra* n.2, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 at p. 31,537-40 (1989).

arrangements outside of the NGA's certification requirements.[32] For example, NGPA Section 311(a)(1) authorized the Commission to approve the transportation of gas by an interstate pipeline on behalf of any intrastate pipeline and any LDC. In sum, the NGPA's aim was to permit a competitive wellhead market where market forces play a "more significant role in determining the supply, the demand, and the price of natural gas."[33]

The NGPA, therefore, radically changed a key aspect of the natural gas industry by eliminating Commission-determined prices for first sales of natural gas. In doing that, the NGPA "reflect[ed] the workably competitive nature of the production industry."[34] Moreover, the NGPA accelerated a fundamental change in the natural gas industry — "natural gas . . . [became] a separate and distinct economic *commodity*: distinct from oil, distinct from transportation, and distinct from storage and various load balancing services."[35]

In 1985, the Commission adopted Order No. 436[36] in

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32. Section 601(a)(2)(A) of the NGPA provides that the Commission does not have NGA Section 1(b) jurisdiction over NGPA Section 311 transportation.

33. Transcontinental Gas Pipe Line Corp. v. State Oil and Gas Board of Miss., 474 U.S. 409, 422 (1986).

34. Order No. 436, *supra* n. 2 at p. 31,470. *See also* Pennzoil Co. v. FERC, 645 F.2d 360, 378-79 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

35. *Id.* at pp. 31,472-73 (emphasis in original).

36. See n.2, *supra*.

response to the NGPA's aim to permit a more competitive wellhead market and to the economic changes in the natural gas industry.[37] Order No. 436 instituted open-access, non-discriminatory transportation to permit downstream gas users such as LDCs and industrials to buy gas directly from gas merchants in the production area and to ship that gas via the interstate pipelines.

To achieve open access transportation, Order No. 436 adopted three key regulations that are pertinent here. First, pipelines were required to permit their firm sales customers to convert their firm sales entitlements to a volumetrically equivalent amount of firm transportation service over a five-year period.[38] Second, the pipelines were required to offer their open-access transportation services without discrimination or preference.[39] Third, the pipelines were required to design maximum rates to ration capacity during peak periods and to maximize throughput for firm service during offpeak periods and for interruptible service during all periods.[40] Order No. 436 thus provided the downstream gas purchasers with an alternative to buying gas from the pipelines in the distribution area under the pipelines' bundled sales services.

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37. See the discussion in Order No. 436, *supra* n.2 at pp. 31,469-70 and 31,472-74.

38. 18 CFR 284.10.

39. 18 CFR 284.8(b) and 284.9(b). The pipelines could impose reasonable operational conditions to effectively manage their systems. 18 CFR 284.8(c) and 284.9(c).

40. 18 CFR 284.7(c)(1) and (2).

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Order No. 436's open-access transportation program has accomplished, in part, its goals of increasing competition and treating the sale of gas and the transportation of gas as separate economic transactions. Two facts attest to the considerable success of Order No. 436. First, an active and viable spot market has developed for gas.[41] Second, the role of pipelines has changed from primarily merchants of natural gas in the distribution area to both merchants of natural gas and nondiscriminatory transporters of natural gas owned by others.

Indeed, pipeline transportation now accounts for about 79 percent of total annual interstate pipeline throughput.[42] This reverses the historical function of pipelines, which prior to Order No. 436 acted primarily as gas merchants.[43] Today, gas

41. See the Commission staff study in Interim Gas Supply Charges and Interim Gas Inventory Charges, Notice of Proposed Policy Statement, "Use of Spot Market Prices for Sales Service and Gas Inventory Charges", 47 FERC ¶ 61,294 Appendix at pp. 62,036-62,040 (1989) ("Staff concludes that the spot market is a well functioning market in the sense that it is broad and that prices do indicate its responsiveness to supply and demand[.]" *Id.* at p. 62,036).

42. Energy Information Administration/Natural Gas Monthly (Feb., 1992); DOE/EIA-0130 (92/02), From: Table 15. Natural and Other Gases Produced and Purchased by Major Interstate Natural Gases Pipeline Companies, 1985-1991 (around 80 percent transportation); Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1990 (July, 1991), From: Table A-1, Carriage for Distributors, End-Users, and Marketers and Sales Summary (79 percent transportation) (INGAA July 1991 paper). The updated INGAA paper shows transportation at 83 percent for the first half of 1991. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through the First Half of 1991 (November 1991), From: Table A-1 Carriage for Distributors, End-Users, and Marketers and Sales Summary (INGAA November 1991 paper).

43. In 1984, transportation amounted to 8 percent of the total gas carried to market by pipelines. INGAA November 1991 paper, *supra*, Table A-1.

transported on behalf of nonpipeline shippers plays a major role in providing service to customers, including service during the winter heating season.[44] The active spot market and significant pipeline transportation of gas owned by others illustrate that pipelines and other gas merchants, such as producers and marketers, are vigorously competing in the sale of gas to LDCs and other end users.

To repeat, the NGPA and Order No. 436 fundamentally changed two key components of the natural gas industry. First, the price of natural gas as a commodity was no longer subject to Commission-determined rates. Second, the transportation and sale of natural gas became distinct economic and commercial services. In that manner, pipelines and other gas merchants have become direct competitors in the sale of gas to LDCs and to end users, such as industrials or gas-fired electric generators.

In 1989, Congress built upon the significant changes in the natural gas industry shaped by the NGPA and Order No. 436 by enacting the Decontrol Act.[45] This legislation amended the NGPA "to repeal all remaining price controls on wellhead or 'field' sales of natural gas"[46] in order to obtain "more abundant [gas] supplies" at "lower prices" by creating competition among

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44. In the first quarter of 1990, sales gas amounted to 29 percent of total carriage delivered to market. In the first quarter of 1991, that figure was 21 percent. The remainder was gas carried to market for LDCs, for end users and for marketers. INGAA November 1991 paper, *supra*, Table A-1.

45. Pub. L. No. 101-60, 103 Stat. 157 (1989).

46. H. R. Rep. No. 29, *supra*, at p. 2.

a "set of efficient producers."[47] The House Committee Report stated that the Commission's "current competitive 'open access' pipeline system [should be] maintained" and further described the importance of open access transportation as follows:

> The Committee stresses that these new rules, and especially the wide adoption of blanket certificates for non-discriminatory open access interstate transportation of non-pipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies. [48]

The House Committee Report further urged the Commission "to retain and *improve* this competitive structure in order to maximize the benefits of decontrol."[49]

The Decontrol Act did not, however, alter the NGA's consumer protection mandate. Indeed, the House Committee Report stated:

> Though not protected by remaining wellhead

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47. *Id.* at 7.

48. *Id.* at 6.

49. *Id.* (Emphasis added).

> controls, consumers still have a stake in how FERC handles gas pipeline transportation issues and allocates gas costs. This legislation does not deregulate gas pipelines. . . . [50]

Similarly, the Senate Committee Report stated that "the purpose [of the legislation] is to promote competition for natural gas at the wellhead in order to ensure consumers an adequate and reliable supply of natural gas at the lowest reasonable price."[51] In addition, the Senate Report stated:

> While this bill decontrols the first sale of natural gas, it does not deregulate interstate natural gas pipelines. The term "first sale", as defined by section 2(21) of the NGPA, expressly excludes "the sale of any volume of natural gas by any interstate pipeline." A pipeline's obligation to serve its customers arises out of the Natural Gas Act and is not affected by the decontrol of first sale transactions under the NGPA. [52]

To sum up, in the evolution of the natural gas industry from passage of the NGA in 1938 to the passage of the Decontrol Act, the industry has been transformed from the "traditional" structure where "pipelines purchased gas from producers [at regulated prices] and transported that gas to consuming markets where it was resold to LDCs [at regulated prices] and end

50. *Id.* at 4.

51. S. Rep. No. 39, *supra*, at p. 1.

52. *Id.* at 9.

users"[53] to a new structure where "LDCs and industrial end users increasingly have utilized pipelines only to transport [at regulated rates] the gas that they purchase [at decontrolled prices] directly from producers and marketers."[54] Indeed, as stated above, the role of natural gas pipelines has changed significantly, since pipeline transportation services now account for 79 percent of pipeline throughput.[55] This is a significant reversal from the pipelines' pre-Order No. 436 primary role as merchants of a bundled sales service.

Hence, at present, pipelines compete with other sellers of natural gas for sales to LDCs and end users, such as industrials and gas-fired electric generators. However, under the present regulatory structure of the natural gas industry, those competitors move their gas through the pipeline network using mainly interruptible transportation service, which amounted to 51 percent of deliveries for market in 1990.[56] Most pipelines, on the other hand, sell their gas in the distribution area on a firm basis and, therefore, use the firm transportation embedded within their bundled, firm sales service to move their gas. The interruptible transportation used to move much of the gas competing with pipeline gas is, by definition, inferior to the firm transportation included within the bundled, firm sales service.

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53. *Id.* at 6.

54. *Id.*

55. INGAA November 1991 paper, *supra*, Table A-1.

56. INGAA November 1991 paper, *supra*., Table A-6, Sales and Firm and Interruptible Transportation as a Percentage of Total Deliveries for Market through First Half 1991. In the first half of 1991, interruptible transportation amounted to 52 percent of total deliveries for market. *Id.*

In addition, although competitors moved their gas through the pipeline network in 1990 using firm transportation amounting to 28 percent of total deliveries for market,[57] this firm transportation, as discussed below, is inferior in quality to the firm transportation embedded within the pipelines' bundled, city-gate, firm sales service. Simply put, the latter service has access to essential facilities and services, such as storage, that are not generally available to shippers currently using firm transportation. Hence, the natural gas industry has not completed its evolution to the point where all gas is shipped on even terms without regard to the identity of the supplier.

V. THE ANTICOMPETITIVE EFFECT OF THE CURRENT REGULATORY ENVIRONMENT AND PIPELINE SERVICES

The fundamental issue before the Commission is whether the current regulatory structure provides all gas sellers with the same opportunity to compete for gas purchasers. The Commission must examine the current pipeline sales services and firm and interruptible transportation services as well as its regulatory methods to determine whether they operate to give competitive advantages and disadvantages to the various participants in the natural gas industry. If the Commission concludes that its current regulatory structure and the current form of bundled pipeline services are unduly discriminatory and anticompetitive, and therefore unlawful under NGA Section 5,[58]

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57. *Id.* In the first half of 1991, firm transportation amounted to 31 percent of total deliveries for market. *Id.*

58. NGA Section 5(a) provides in pertinent part that:

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it *must* fashion a remedy that corrects the undue discrimination.[59] This remedial action must not undermine the quality or reliability of services received by the pipeline customers. For, as discussed below, it is vital that pipeline customers continue to have access to an adequate and reliable supply of gas when needed to meet the needs of gas consumers at all times.

In 1990, although 21 percent of pipeline deliveries to market were pipeline sales as opposed to transportation of gas,[60] a disproportionate amount of pipeline capacity was reserved for pipeline firm sales services. This is attested to by the fact that, in 1990, 51 percent of the pipeline deliveries to market used

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> Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. . . .

59. Office of Consumers' Counsel v. FERC, 783 F.2d 206, 236 (D.C. Cir. 1986).

60. INGAA November 1991 paper, *supra*, Table A-1. Table 1 to this (Cont'd)

interruptible transportation.[61] This considerable movement of gas by interruptible transportation shows that firm sales customers have not converted their firm sales entitlements to firm transportation service. According to INGAA, "[c]onversions of maximum daily quantity (MDQ) rights amounted to slightly over 24 percent, or 8.5 Bcf/day, for the . . . period [1988-1990]."[62] This is confirmed by the pipeline capacity reports filed with the Commission under Section 284.12 of the regulations. The 1991 Capacity Reports for major pipelines that made bundled sales show that over 60 percent of peak day capacity on major pipelines was reserved for pipeline firm sales service. This is shown by Table 2 below. For those same pipelines, as shown in Table 3, 1990-91 pipeline sales accounted for only 18.8 percent of total throughput.

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order sets forth pipeline "Sales Share as a % of Total Gas Delivered for Market" from 1984-1991. Most of the sales were firm sales.

61. INGAA November 1991 paper, *supra*, Table A-6. The remaining 28 percent of the throughput was firm transportation.

62. INGAA July 1991 paper, *supra*, at p. 3. INGAA further stated that "[o]f the 22 responding pipelines, none reported contract demand conversions prior to 1988." *Id.* n. 7. The Commission lifted the stay on the effectiveness of 18 CFR 284.10, which permits contract demand conversions, effective November 1, 1987. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 FR 35539 (Sept. 22, 1987), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,764 (1987).

Appendix B

Table 1

(Omitted here but submitted separately as Lodging Appendix).

Appendix B

Table 2

(Omitted here but submitted separately as Lodging Appendix).

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While pipeline sales were less than 20 percent of total throughput on the major pipelines, during the three day period of peak usage, pipeline sales were approximately 50 percent of total deliveries (see Table 3). The seasonal nature of the pipeline sales indicates that customers rely on pipeline sales during periods when capacity is most likely to be constrained. For example, as Table 3 shows, approximately 85 percent of the sales Docket Nos. RM91-11-000 and RM87-34-065 by Tennessee Gas Pipeline Company and Williams Natural Gas Company occurred duirng the winter months. On many other pipelines 70 percent or more of their sales were made during the winter season, and overall approximately 65 percent of pipeline sales were made in the winter months. This is illustrated in Table 3.

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Table 3

(Omitted here but submitted separately as Lodging Appendix).

The result is that while a large portion of pipeline capacity is reserved for firm sales, pipeline sales customers prefer to buy their gas from other sellers and have it transported using interruptible transportation. However, during peak winter periods pipeline sales predominate over sales by other gas sellers. The result is an inefficient market that disadvantages all segments of the gas industry as discussed further below.

Gas buyers are disadvantaged because they are paying the demand charges for firm pipeline sales service, and, in addition, paying the interruptible rates to transport gas purchased from other sellers. Instead of buying gas from the pipeline or converting to firm transportation, gas buyers are choosing to purchase gas from nonpipeline merchants and transporting the gas to market using an inferior form of transportation. As shown in Table 4, the price of pipeline gas generally has been 20 to 80 cents higher per Mcf than the price available from other sellers. Thus, it is often cheaper for pipeline sales customers to buy gas on the spot market, and pay the pipeline's demand charge plus the interruptible rate, than to purchase the pipeline's gas. This is inefficient and disadvantages customers because they must pay extra for the inferior interruptible transportation service even though it is used in lieu of firm transportation rights embedded within their bundled, city-gate, firm sales services.

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Table 4

(Omitted here but submitted separately as Lodging Appendix).

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The main reason that pipeline sales customers have not converted to firm transportation to satisfy their needs is that the transportation embedded within the pipeline's bundled city-gate, firm sales service is superior in quality to the pipeline's separately available firm transportation service. This is because, as the commenters opposing mandatory unbundling amply prove, the transportation embedded within the pipeline's bundled, city-gate, firm sales service is more reliable and flexible to meet their peak needs than the firm transportation service that is available to be combined with sales by nonpipeline merchants.[63] For example, firm transportation is less flexible than pipeline sales service because most firm transportation is subject to daily scheduling and balancing requirements that do not apply to sales service. In addition, a firm transportation shipper may be penalized if its daily swings vary by more than 10 percent from the amount the shipper scheduled for transportation, whereas sales customers do not pay penalties for variances from their projected purchases.

Under current circumstances pipeline sales service is more reliable because the pipelines' ability to make timely deliveries on demand is greater than their competitors' ability to do so. Simply put, the pipelines' bundled, firm sales service has available to it component services not available to firm transportation. For example, many pipelines have access to substantial storage capacity to aid their own sales, but many pipelines do not provide open access, contract storage services

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63. A comparison of the share of pipeline sales to total deliveries for market by quarters also attests to the superiority of pipeline bundled sales services. As shown in Table 1, pipeline sales in the first (January, February, and March) and fourth quarters (October, November, and December) are greater than their shares for the rest of the year.

for others.[64] This limits the firm shippers' ability to aggregate supplies for future use in a manner similar to the pipeline's aggregating ability.[65] In addition, pipelines entered into contracts with other pipelines for upstream capacity rights when the pipelines were providing very limited transportation services. Pipelines with those capacity rights on upstream pipelines are able to reach more producers than gas purchasers without that capacity.[66] Thus, the firm transportation service embedded within the pipelines' bundled, city-gate, firm sales service is superior to the pipelines' open access firm transportation service. This means that pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors.

The Commission believes that this lack of comparability between pipeline open access firm transportation service and pipeline bundled, city-gate, firm sales service is a major reason why pipeline customers have not converted to firm transportation service to a greater degree.[67] Indeed, the commenters opposing mandatory unbundling specifically cited the difference in quality

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64. Contract storage means that a pipeline customer has a contract with the pipeline which enables the customer to inject its own gas into and withdraw that gas from the pipeline's storage facilities.

65. See *infra* on storage.

66. See *infra* on upstream pipeline capacity rights.

67. Many commenters assert that until the issuance of Order No. 500-J, on February 13, 1991, uncertainty about the Commission's pregranted abandonment rule hindered conversions. See n.16, *supra*.

between pipeline firm sales and firm transportation as the reason why customers had not converted to firm transportation.[68]

This means that considerable firm capacity rights are restricted to pipeline sales gas and may not be used to move gas sold by others on a firm basis. Thus, gas sold by others must often move through interruptible transportation — which reduces its quality and value especially during peak demand periods.

The result is that nonpipeline gas sellers are also disadvantaged because they cannot compete for long-term supply arrangements since their access to superior firm transportation is artificially limited and their gas is therefore transported on an interruptible rather than a firm basis. This movement of gas sold by others via mainly interruptible transportation results in facially uneven competition between pipeline merchants and other gas suppliers because firm sales service is of a higher quality than interruptible transportation service by definition. Of necessity, this inhibits nonpipeline gas suppliers in their quest to secure long-term supply arrangements with LDCs and end users, such as industrials and gas-fired electric generators because, unlike the pipeline, those merchants cannot assure delivery at the city-gate in all circumstances. Simply put, the pipeline can interrupt its competitor's transportation service on reasonable notice when the pipeline needs the capacity for its own bundled, city-gate, firm sales service. Moreover, gas purchasers are inhibited from securing long-term supply arrangements with nonpipeline gas suppliers because the gas must often move through interruptible transportation, or at best inferior firm transportation.

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68. Reply Comments of United Distribution Companies (UDC) at 7 ("The remaining pipeline sales service is largely used to provide swing service during the winter months and therefore cannot be converted absent comparable transportation.").

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While gas purchasers and nonpipeline sellers are clearly disadvantaged under current circumstances, pipelines are not the beneficiaries. Pipelines also are disadvantaged by the current environment. Pipelines have certificate and contractual obligations that require them to stand ready to provide gas on demand without notice. However, the pipeline's sales customers are under no obligation to buy gas from the pipeline. Compounding the pipelines' difficulty is that under existing regulations they cannot have the kind of pricing flexibility they need to price their gas to compete with unregulated sellers. As a result, pipelines have suffered a significantly declining share of the sales market since the adoption of Order No. 436.[69]

The Commission believes that the primary reason for this is the way that pipelines sell their gas. Pipelines are allowed to earn only a regulated return on their transportation business. Because pipelines sell gas bundled with a transportation service over which they possess market power, the Commission requires pipelines to sell their gas at cost to ensure that pipelines cannot shift the recovery of monopoly profits from their transportation service to the sale of the, now deregulated, commodity. The cost-based rate at which the Commission has required the pipelines to sell their gas is their weighted average cost of gas (WACOG). The Commission does not permit a pipeline to sell gas at a market rate unless the pipeline demonstrates that its sales markets are sufficiently competitive to prevent it from exercising significant market power. To make its case, the pipeline must show that its firm transportation service is comparable in quality to the firm transportation embedded within its firm sales service[70] and that

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69. See Table 1.

70. *E.g.*, United Gas Pipe Line Co., 55 FERC ¶ 61,330 at p. 61,974 (Cont'd)

adequate divertible gas supplies exist in its sales markets.[71] Most pipelines have not switched from cost-based, WACOG pricing to market-based pricing. Therefore, they are at a disadvantage when competing with the unregulated, market-based pricing of other merchants in the gas supply market. Because recently the WACOG has been above the spot gas price, pipeline customers often choose to buy their gas elsewhere and ship it under the pipelines' interruptible transportation services.[72]

In sum, under the current situation pipelines are disadvantaged in selling gas through WACOG pricing, customers are disadvantaged by using interruptible transportation in addition to paying the demand charges for firm sales, and nonpipeline sellers are disadvantaged because their gas must move mostly with interruptible transportation.

Based upon the record here and the Commission's observations of the gas industry since the advent of open-access

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(1991) ("United must specifically demonstrate that its transportation services and storage services available to firm transportation customers are comparable to the transportation and storage in its bundled service offered at market-based rates.").

71. The Commission has found that a pipeline's sales are made in a sufficiently competitive market when the pipeline provides comparable transportation service with respect to all gas supplies from whomever purchased and when adequate divertible gas supplies exist. *E.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

72. See Table 4.

transportation, the Commission believes that the main reason for this current situation, which disadvantages all segments of the natural gas industry, is the continued existence of the pipelines' bundled, city-gate, firm sales service. This service reserves a considerable amount of pipeline capacity throughout the year in order to ensure peak service. Hence, pipelines must sell at their WACOG throughout the year and gas purchasers must use a considerable amount of interruptible transportation to acquire competitively priced gas from other gas sellers. In addition, the pipelines' existing bundled, city-gate firm service gives pipelines an undue competitive advantage over other natural gas suppliers in making peak sales because nonpipeline merchants must deliver gas to their customers using inferior firm and interruptible transportation services.

The bundled, city-gate firm sales service gives pipelines an undue competitive advantage *vis a vis* other gas merchants that is not in the public interest as described by Congress in enacting the Decontrol Act. Pipeline transportation of its own gas on superior terms over the transportation (mainly interruptible) of other supplies will inhibit the "unimpeded transmission of market signals" and the "unimpeded operation of market forces" so that gas purchasers and sellers will be forced to make decisions in "distort[ed] natural gas markets" because of "erroneous market signals".[73] Over the long-run, this uneven transportation will, therefore, inhibit the production of an adequate supply of natural gas at reasonable prices and retard the nation's ability to reduce its dependence on foreign oil and to solve environmental problems by greater use of clean and abundant domestic natural gas.[74]

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73. S. Rep. No. 39, *supra*, at p. 2.

74. *Id.* and H.R. Rep. No. 29, *supra*, at p. 2.

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The pipelines' bundled, city-gate, firm sales service, therefore, has a harmful impact on competition between pipelines and other gas merchants, on the creation of a national wellhead market for gas where consumers will have access to an adequate supply of gas at reasonable prices, and on the nation's need to rely more on clean and abundant domestic natural gas. However, the Commission realizes that the pipelines' bundled, city-gate, firm sales service has the objective of providing a "no-notice" service where firm sales customers can receive gas up to their daily contract entitlements on demand without nominating that amount or incurring a penalty.[75] The delivery of supplies on a "no-notice" basis is in the public interest because it enables pipeline customers to meet unexpected changes in peak service needs caused, for example, by an unexpected change in temperature.

In evaluating a "rule, regulation, practice, or contract,"[76] the Commission "must carefully balance the competitive harm the term causes against the term's objectives in light of the alternatives available for achieving those objectives."[77] In this instance, the "term" upon which the Commission has focused

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75. The Commission understands that the pipeline and its customers are in close communication throughout the day. Nonetheless, the existing sales customer is not bound by any initial nominations or updated nominations.

76. NGA Section 5(a), *supra*.

77. Transwestern Pipeline Co., 36 FERC ¶ 61,175 at p. 61,439 (1986), *aff'd*, Transwestern Pipeline Co. v. FERC, 820 F.2d 733 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988) (The court affirmed the Commission's elimination of Transwestern's fixed cost minimum bill as not justified in view of its competitive harm.).

is the pipelines' bundled, city-gate, firm sales service and its impact on the current competitive environment. The Commission will strike down or alter a contract as an unreasonable restraint of trade "[o]nly if on balance the term causes more harm than is warranted in light of the term's objectives and the available alternatives[.]"[78]

Based upon the extensive record developed in this entire proceeding,[79] as well as the Commission's observations of the industry, the Commission finds that the pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry as described above. The Commission finds that this harm has an unreasonable impact on gas sellers and gas purchasers and is an unlawful restraint of trade which is not balanced by the "no-notice" aspect of the bundled, city-gate sales service because, as fully discussed below, the pipelines can and will be able to provide a "no-notice" transportation service for all gas supplies without the competitive harm attendant to the current bundled, city-gate, firm sales service. Restricting access to a "no-notice" service by limiting its availability to the purchase of pipeline sales gas is anticompetitive. The bundled, city-gate, firm sales service provides the pipelines with an undue advantage and subjects other gas merchants to an undue disadvantage. It maintains an

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78. *Id.* (The Commission found that "Transwestern's minimum bills caused more harm than was warranted . . . [and] concluded that the minimum bills unreasonably restrained trade and hence were unjust and unreasonable.").

79. As discussed, *infra*, the Commission received comments in connection with a May 10, 1991 public conference, the Notice of Proposed Rulemaking, issued July 31, 1991, and a technical conference held on January 22, 1992.

unreasonable difference in service between classes of service (bundled, city-gate, firm sales and open access firm transportation) because the firm transportation embedded within the firm sales is superior in quality as discussed above. The Commission, therefore, finds and concludes that the pipelines' bundled, city-gate, firm sales service violates NGA sections 4(b) and 5(a).

The Interstate Natural Gas Association of America (INGAA) disputes the Commission's conclusion that the pipelines' bundled, city-gate, firm sales service is anticompetitive. INGAA states that "pipeline bundled sales service is not an impediment to the sellers of firm sales service and therefore is not anticompetitive."[80] INGAA refers to its 1990 numbers which show that "firm transportation volumes for non-pipeline shippers accounted for 28 percent of total volumes delivered for market compared with pipeline sales of 21 percent."[81] INGAA states that this demonstrates that "pipelines are no longer the dominant providers of the merchant service."[82]

As discussed above, the Commission believes that this decline in pipeline sales is due to their selling gas under cost-based, WACOG pricing of the bundled, city-gate, firm sales service. Moreover, INGAA fails to note the fact that firm sales customers have not reduced their sales CD entitlements by nearly as much as they have reduced their purchases.

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80. Initial Comments at 8.

81. *Id.* at 9.

82. *Id.*, quoting INGAA July 1991 paper, *supra*, at p. 1.

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The Commission draws a different conclusion from INGAA's numbers with respect to long-term gas supply arrangements and sales to meet the peak needs of gas purchasers. The Commission concludes that in those situations the pipelines have a competitive advantage because the firm transportation embedded within their bundled, city-gate, firm sales service is superior in quality to both the firm transportation and the considerable amount of interruptible transportation used to move gas sold by nonpipeline merchants to LDCs and end users, such as industrials and gas-fired electric generators.[83] In particular, the Commission finds that the pipelines have an undue advantage over their merchant competitors in securing long-term gas supply arrangements with customers because, as discussed above, the pipelines currently have a superior ability to deliver gas on demand to meet the peak needs of LDCs and other customers. For example, the pipelines have access to storage to meet the customers' needs on demand.[84] In general, nonpipeline merchants have not been able to obtain access to storage for the gas that they sell because the Commission has not required the pipelines to offer open access contract storage.[85] The pipelines'

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83. Interruptible transportation amounted to 51 percent of total deliveries for market in 1990. INGAA November 1991 paper, *supra*, Table A-6.

84. Withdrawals from storage are significantly greater during peak months than during offpeak months. Energy Information Administration/ Monthly Energy Review (Feb., 1992); DOE/EIA-0135 (92/02), From: Table 4.2, Natural Gas Supply and Disposition; Energy Information Administration/ Natural Gas Monthly (Feb., 1992); DOE/EIA-0130 (92/02), From: Table 18, Underground Natural Gas Storage — Interstate Operators of Storage Fields, 1985-1991.

85. See *infra* on storage.

competitive advantage *vis a vis* the needs of gas purchasers at peak is shown by the significantly increased share of pipeline sales to total deliveries for market in peak quarters over nonpeak quarters, and by the significantly higher prices they receive for gas (see Table 4). In 1989-1990, the percentage of pipeline sales in peak quarters was double its share in offpeak quarters,[86] and in 1990-91 two-thirds of pipeline sales were in the winter months (see Table 3). Thus, the Commission draws a different conclusion from INGAA's numbers.

The Commission finds that the pipelines' bundled, city-gate, firm sales service gives pipelines an undue advantage over other gas sellers because of the superior quality of the "no-notice" aspect of the transportation embedded within the bundled, city-gate, firm sales service when compared to the firm and interruptible transportation available for the gas of nonpipeline gas sellers. The Commission understands the counter argument made by the pipelines. That is, unless they are relieved of their service obligation to their firm sales customers, they must maintain the ability to serve those customers at peak. As noted above, their firm sales customers do not buy most of their gas from the pipelines, but the pipelines must be ready to serve them by selling gas to them during periods of peak demand. This situation is the nub of the service obligation problem that the Commission is addressing in this order. In order to secure a more efficient marketplace, the Commission must address the lack of equality in transportation (and storage) services, the pipelines' dominance in the peak period sales, the lack of flexibility in pipelines' sales pricing, and the pipelines' remaining service obligation simultaneously.

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86. See n. 63, *supra* for a comparison of pipeline sales for peak and offpeak quarters.

Appendix B

The Commission recognizes that over the past several years, the pipeline industry has been moving toward improving the quality of firm transportation and storage services available to competing sellers. However, the amount of capacity reserved for pipeline firm sales still far exceeds the pipelines' actual sales so that capacity is not available for firm transportation and, as a result, interruptible transportation maintains a significant share of peak period transportation. Thus, competing sellers continue to be at a disadvantage. In addition, firm transportation service is still subject to many more restrictions than necessary as compared to pipeline bundled firm sales service. Therefore, although the trend in the industry has been moving toward more even competition, the Commission finds it necessary to act here to accelerate and complete the transition toward a more efficient market.

In sum, the Commission believes that all segments of the natural gas industry are unduly disadvantaged by the current regulatory structure of the industry. The Commission must, therefore, act under NGA section 5 to determine the just and reasonable "rule, regulation, practice [and] contract[s]" to be "observed and in force".[87]

VI. THE REMEDY

A. The Remedy Proposed in the NOPR

Having found the current regulatory structure leads to unjust and unreasonable results, the question remains what the appropriate remedy is to address this situation. On July 31, 1991, the Commission proposed changes to its regulation of

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87. NGA Section 5(a), *supra*.

interstate natural gas pipelines to remedy the pipelines' undue competitive advantage.[88] The July 31 Notice of Proposed Rulemaking (NOPR) was, among other things, the outcome of a public conference held on May 10, 1991, where members of the natural gas industry discussed with the Commission the role of interstate natural gas pipelines in today's natural gas markets.[89]

In brief, the NOPR proposed to amend Part 284 of the Commission's regulations [90] as follows:

° Pipelines would be required to unbundle (*i.e.*, separate) their sales and transportation services with one exception for continued bundled sales to small customers. Pipelines would, however, be allowed to repackage their unbundled services to replicate their bundled, city-gate, sales services.

° The definition of transportation would be amended to include storage so that storage would be provided on an open access contract basis.

° Pipelines would be required to provide an open access transportation service that is comparable in quality for all

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88. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 FR 38372 (Aug. 13, 1991), IV FERC Stats. & Regs. ¶ 32,480 (1991).

89. All future references to pipelines are to interstate pipelines. Except for expanding the Part 284 definition of transportation to include storage, the regulations adopted by this order do not apply to intrastate pipelines.

90. 18 CFR Part 284.

gas supplies, whether purchased from the pipeline or elsewhere.

° Firm transportation customers of downstream pipelines would be assigned capacity on upstream pipelines now held by downstream pipelines.

° Pipelines would be required to implement a capacity releasing program.[91]

° Pipelines would be granted blanket certificates for unbundled sales services and would be subject to standards of conduct in connection with unbundled sales services similar to those applicable to affiliate sales.[92] The unbundled sales services would be subject to pregranted abandonment.

° Pipeline transportation rates would be designed under the Straight Fixed Variable method unless the parties to a proceeding otherwise agree (however, measures would be permitted to mitigate cost shifts, if necessary).[93]

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91. The NOPR proposed that capacity brokering certificates be individually terminated.

92. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec. 22, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. & Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992).

93. Straight Fixed Variable is defined *infra*.

° Pipelines would be required to initiate restructuring discussions with all interested parties within 30 days of the effective date of the Final Rule and to file a restructuring plan on or before the required date set forth in the regulations. Prior to the effective date of a restructuring filing, the holders of firm capacity would be required to exercise a right of first refusal by giving notice that they want to continue their contractual arrangement and that they agree to match and pay any greater rate up to the maximum rate and to match the most favorable contract term offered by others seeking firm capacity.

B. Comments on the NOPR

The NOPR proposed to require pipelines to unbundle (*i.e.*, separate) their sales and transportation services with one exception for continued bundled sales to small customers. A substantial number of commenters from all segments of the natural gas industry support the NOPR's mandatory unbundling proposal.[94] However, a substantial number of pipeline and LDC commenters oppose mandatory unbundling.[95] In brief, they state that, on some pipelines, a bundled, city-gate, firm sales service is necessary so that pipeline customers can receive service on demand to meet unexpected changes in peak service needs

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94. *E.g.*, Natural Gas Supply Association and Indicated Producers (NGSA), Independent Petroleum Association of America (IPAA), Transcontinental Gas Pipe Line Corporation, Consolidated Edison Company of New York, Inc., and the Public Service Commission of the State of New York.

95. *E.g.*, Interstate Natural Gas Association of America, Coastal Companies, Distributors Advocating Regulatory Reform (DARR), and Cincinnati Gas and Electric Company.

caused, for example, by an unexpected change in temperature. This is known as "no-notice" service.[96]

In addition, it is stated that pipelines will not be able to provide instantaneous transportation service if they must unbundle their sales and transportation services.[97] Instantaneous service occurs when the pipeline delivers gas to its downstream customer when the gas is injected into the pipeline upstream. This differs from "no-notice" service where a pipeline customer can take delivery without regard to injections into the pipeline system at the same time.

On January 22, 1992, representatives from all segments of the natural gas industry discussed with the Commission at a technical conference issues with respect to the operational aspects of the NOPR. In connection with that conference, interested persons filed written responses to questions posed by the staff in the appendix to the notice of the technical conference.[98] The information obtained at the technical conference, as well as from the initial and reply comments to

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96. The firm sales customer may purchase gas up to its firm daily contract entitlement without incurring a penalty and even though the customer and the pipeline are in close communication, the customer is not bound by any initial nominations or updated nominations.

97. Initial Comments of Texas Eastern Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, and Algonquin Gas Transmission Company (PEC Pipeline Group) at 16-17.

98. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 57 FR 385 (Jan. 6, 1992).

the NOPR,[99] has been very helpful to the Commission in fashioning the final rule. The Commission has evaluated all the comments received but specifically addresses below only those that opposed the action adopted in this final rule. Comments that addressed proposals in the NOPR that are not adopted in this final rule are not specifically addressed, nor are comments that raised issues not relevant to the decisions reached here.

C. Remedial Action in the Final Rule

The question is what remedial action is appropriate to counter the pipelines' undue advantage as merchants providing bundled, city-gate sales service while retaining the reliable, "no-notice" service for pipeline customers that want such a service. As stated above, the NOPR proposed to eliminate the bundled, city-gate, sales service with an exception for small customers, and recognized that pipelines could package their various services to achieve the equivalent of a bundled, firm sales service.

Significantly, the representatives of the pipeline industry participating in the technical conference indicated a significant shift in their position from that stated in the written comments. Initially, the pipelines took the position that the bundled, city-gate, firm sales service is essential to the providing of "no-notice" and instantaneous service. However, at the technical conference they acknowledged that pipelines can provide those services for the delivery of any shipper's gas if permitted to retain adequate operational control of the use of their facilities.[100]

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99. The Commission has accepted and considered all comments filed, including late-filed comments.

100. *E.g.*, compare INGAA Initial Comments at 3,4 and Technical Conference Tr. 36-38.

Indeed, the information received at and after the technical conference reveals that a significant majority of the public — cutting across all segments of the industry — share and support this proposition.

The comments received at the technical conference highlighted several important matters. First, unbundling should have no perceptible effect on the reliability of a pipeline's peak day delivery services for heat sensitive residential loads. Second, the Commission, most pipelines, producers, most LDCs, marketers, and industrials agree that the pipeline should maintain operational control of the pipeline facilities, but importantly, in a manner that does not constitute any compromise of nondiscriminatory, fully equal, transportation services. Third, there are a number of operating and contractual tools to ensure that the pipeline, its customers and its shippers will take the necessary actions to maintain the reliable operation of the system — and those tools are not theoretical or speculative. They are in use today on the El Paso, Northwest and Transco systems and they have been proposed for the Northern Natural system. The details would be among the issues that would be worked out in the restructuring proceedings. Fourth, the comments strongly evidence that current pipeline services, in fact, can be unbundled into separate transportation, storage, and balancing services with complete equality of treatment for all gas supplies, price transparency and without cross-subsidization so that customers are offered a menu of unbundled services. And, fifth, there is general agreement that *one* form of bundled transportation service that can be offered would be the no-notice peak service on which some LDCs continue to claim reliance, with either pipeline or nonpipeline supplied gas.

The Commission has shaped this rule, in part, in response

to those comments by creating a new "no-notice" firm transportation service under which gas customers will be able to receive gas up to their daily contract entitlement without incurring a penalty (see *infra* for a discussion of "no-notice" transportation service). In light of the views expressed at the technical conference, the Commission is confident that the pipelines can unbundle their services and, by retaining operational control of their systems, transport gas, whether purchased from a pipeline or nonpipeline supplier, on a basis that is just as adequate and reliable as the current bundled, city-gate, firm sales service in meeting the needs of their customers and of gas consumers.

Therefore, the final rule adopts the remedial approach of the NOPR. The Commission finds that it is appropriate to require pipelines to unbundle their sales services from their transportation services at an upstream point near the production area. To accomplish this required unbundling, the Commission is using its authority under NGA section 5 to convert each pipeline's bundled, city-gate, firm sales service into an unbundled firm transportation service. The existing bundled city-gate service obligation is being supplanted through the procedures established by this rule. In its place, pipelines and their existing sales customers will be able to negotiate a new unbundled firm sales service to be performed under a new blanket sales certificate for all pipelines offering open access transportation under Subpart B or G of Part 284 of the Commission regulations, as discussed in greater detail below. After negotiation of a new sales agreement, the pipeline's obligation to sell gas to that customer will be co-extensive with that new agreement. As an additional remedy, the Commission is affording firm sales customers the opportunity during the restructuring proceedings established by this rule (see *infra*) to

reduce their unbundled firm sales entitlements in whole or in part. This will enable those customers to freely negotiate to purchase gas from the pipeline under its new market-based sales service or to purchase gas from other gas suppliers. The end result will be that all gas will move from the production area to the city gate under firm or interruptible transportation service.

The NOPR referred to the possibility of unbundling at the wellhead, at production area receipt points into mainline facilities, at receipt points, at the intersection of separate mainline systems, or at several of those places. In addition, the NOPR recognized the use of pooling areas as a means to facilitate the aggregation of supplies by all merchants. Most commenters support the Commission's proposal to determine places of unbundling on a case-specific basis and not to mandate pooling areas. A few commenters suggest specific places for unbundling[101] while other commenters urge the Commission to mandate pooling areas.[102]

The Commission concludes that the precise places of unbundling should be determined in the restructuring proceedings established by this order. The Commission believes it would be unwise to mandate specific unbundling places for the pipeline industry in light of the different configurations of the pipelines and their sources of supply. However, the place of unbundling should be located as far upstream as possible.

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101. *E.g.*, Tejas Power Corporation states that unbundling should take place at the wellhead while the American Paper Institute states that unbundling should occur at mainline receipt points.

102. *E.g.*, the Independent Petroleum Association of America, Natural Gas Clearinghouse, Brymore Energy, Inc., Vesta Energy Company, and the Natural Gas Supply Association/Indicated Producers.

Similarly, as discussed below, the Commission encourages but will not mandate the establishment of market centers and pooling areas.

The Commission discussed above the pipelines' "no-notice" service where bundled, firm sales customers can receive gas up to their daily contract entitlement on demand without nominating that amount or incurring a penalty. The Commission finds that it is in the public interest for pipelines to provide a firm transportation service that is a "no-notice" service similar to that received under the bundled, city-gate, firm sales service. Therefore, the Commission is requiring all pipelines that make sales for resale on the effective date of this rule to offer in their tariffs a "no-notice" firm transportation service. This service must be available as of the effective date of the tariff sheets to be filed to comply with this rule. This service, discussed in more detail *infra*, must be available to all firm shippers. The mechanics of how this "no-notice" firm transportation service will be provided on a particular pipeline must be considered and developed in the restructuring proceedings established by this rule (see *infra*).

This new "no-notice" transportation service will be provided in addition to, rather than in lieu of, the pipelines' current open-access, firm transportation service where shippers must receive instantaneous but not "no-notice" service. The former "traditional" firm transportation service will still be subject to reasonable nominating, scheduling and other operational conditions, such as imbalance tolerances and penalties. However, the quality of this service should be enhanced under the steps taken here. These operational conditions, of course, must be devised and implemented on a nondiscriminatory basis. In assessing the pipeline's compliance filing, the Commission

will seek to ensure that the pipeline is not attempting, through the "no-notice" transportation service, to simply replace one form of bundled service with another anti-competitive service.

In addition, the pipeline, or another gas merchant, could offer a "packaged" sales and transportation service where the separately sold sales and transportation services are packaged by a contract pursuant to which the gas purchaser allows the pipeline, or another gas merchant, to act as the gas purchaser's agent in making all arrangements necessary to deliver the gas to the city gate.[103] However, the rates for each transportation service must be separately stated in the pipeline's tariff.

Since sales and transportation services must be offered on an unbundled basis, there would be no rate on file with the pipeline's tariff for an "agency" service. The "packaging" of separate services, offered under separate rate schedules, would be effected only by contracts between the gas purchaser and its agent. Whether or not the pipeline as a gas seller can collect a fee for acting as the gas purchaser's agent in arranging for pipeline services is a matter for negotiation between the pipeline and gas purchaser on entering into their sales contract. This is because the pipeline will be acting as agent in its capacity as a gas seller rather than as a gas transporter. Any agency fee would have to be recovered as part of the price for selling gas and not as part of the transportation rate. Of course, the pipeline must act in a non-discriminatory manner in offering agency services.

The Commission is not adopting the NOPR's proposal to continue a bundled, city-gate, firm sales service for small sales

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103. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991).

customers, because those customers can be served reliably through a combination of unbundled sales and the "no-notice" transportation service required by this rule. The pipeline or another gas seller could also act as the agent of the small customers and make all of the arrangements necessary to deliver the gas to the small customers in the same manner as under the current bundled, city-gate, firm sales service. In addition, as discussed further below, the small customers can continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined.[104] Alternatively, as indicated by Florida Cities at the January 22, 1992 technical conference, small customers can band together to purchase gas.[105]

The Commission sees several reasons for requiring the unbundling of pipeline services and the creation of a "no-notice" transportation service, as opposed to retaining the pipelines' bundled, city-gate, sales service.

First, firm shippers will be able to select the form of pipeline transportation service that best suits their needs, both as to the quality and the prices of the individual services chosen. As stated, firm shippers will be able to choose a transportation service that provides "no-notice" service. In the alternative, firm

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104. Existing small sales customer rates are often determined by assuming a quantity of purchases which may be higher than actual purchases. Small customers, therefore, pay less for their service than they would if their rates were designed based on actual purchase levels.

105. Technical Conference Tr. 277,293. In Florida, several municipal utilities banded together with one utility buying on behalf of the others. The Florida Cities representative reported that those utilities have achieved "tremendous economies." *Id.* at 291.

shippers may elect a service of a different quality. For example, firm shippers can elect to continue the traditional open-access firm transportation service, if they do not want "no-notice" service. Or, firm shippers could purchase some combination of services, such as traditional firm transportation service and open-access contract storage. This complete menu of services will enable gas purchasers, sellers, and pipelines to fashion arrangements according to the demand for the services in lieu of the present system which binds individual services with separate costs together into one package. The gas purchaser, or nonpipeline seller will be able to make informed choices about services and the market will decide the need for the various services.

Moreover, the unbundling of pipeline services will enable all gas sellers (producers/marketers/pipelines) to compete on an even basis by offering the same sales services in the same market. At present, most pipeline sales are at the city gate at the WACOG price while most producer or marketer sales are at the wellhead or in the field at the market price. The unbundling of services will create competition for gas purchasers among gas merchants on more even terms. The competition for gas purchasers will not be skewed in favor of pipelines by their ability to offer a superior bundled, city-gate, firm sales service or against pipelines because of WACOG pricing. In addition, the competition between pipelines and other gas sellers in the same market should greatly reduce the pipeline's natural incentive in a bundled service environment to manage its pipeline system to favor itself as a merchant to the disadvantage of shippers of gas sold by others.

The Commission also believes that this new form of "no-notice" transportation service will be superior to the existing

"no-notice" bundled, city-gate, firm sales service. This is because gas purchasers will be able to obtain "no-notice" transportation service for gas supplies purchased from any gas seller, not just from pipelines, rather than relying on inferior firm or interruptible transportation as discussed above.[106] This should enable gas purchasers to enter into more reliable supply arrangements with nonpipeline suppliers for both base and peak needs. Hence, gas purchasers will have more choices and more flexibility. In addition, the pipelines will be able to compete for more gas purchasers under market-based pricing in lieu of their WACOG pricing.

Some commenters argue that the Commission's fostering of competition cannot be a justification in and of itself for the regulations adopted here. Rather, they contend that the Commission is required to foster competition only when consumer interests are advanced and protected.[107] The Citizens Gas & Coke Utility sees nothing wrong with unequal competition so long as the merchants' differing products are appropriately priced. It maintains that "[t]he Commission should *not* mandate a homogeneous group of sellers."[108]

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106. Even if the sales customer elects to continue to contract for its gas needs with the pipeline under a market-based rate that includes a component that compensates the pipeline for standing ready to provide a certain quantity of gas at all times, the customer will have the right to purchase spot gas elsewhere and use its unbundled firm transportation to ship it.

107. *E.g.*, the Cincinnati Gas & Electric Company, Union Light, Heat and Power Company, and Lawrenceburg Gas Company, Initial Comments at 13, 14, *citing*, Brown Shoe Co. v. U.S., 370 U.S. 294, 320 (1962) and Environmental Action, Inc. v. FERC, 939 F.2d 1057, 1061 (D.C. Cir. 1991).

108. Initial Comments at 7.

Appendix B

The Commission is not acting to protect competitors. Rather, the Commission, as discussed in detail above, is acting to improve the competitive structure of the natural gas industry to facilitate the operation of a national wellhead market as envisioned by Congress in order to provide natural gas consumers with access to an adequate supply of clean and abundant natural gas at reasonable prices. Moreover, the Commission is improving this competitive structure without undermining the reliability of service for pipeline customers by requiring pipelines to perform a "no-notice" transportation service. In short, the Commission is both promoting competition and protecting all gas consumer interests, especially with respect to the reliability and the pricing of services.

In addition, the Commission is not mandating a homogeneous group of gas merchants. Rather, the Commission is creating a regulatory environment that will provide all gas merchants with an equal opportunity to compete for gas purchasers. To be sure, not all gas sellers are similar. Some are more efficient than others. Some have greater expertise and some have more resources upon which to draw. However, by separating the various pipeline services needed by gas consumers, the Commission can assure the fair pricing of all services. The gas purchasers will be better off because of the ability to make informed choices about their gas purchasing decisions. Moreover, the rule will not change inherent advantages held by any gas merchant, whether it be a producer, marketer, or pipeline, on account of size, experience, or motivation. The Commission envisions a future gas market where buyers and sellers can meet to fashion deals according to their needs, with no decline in, and indeed with enhancement of, the quality and reliability of service for gas consumers.

To that end, the Commission is amending Part 284 in several ways to upgrade pipeline services used to transport gas, whether sold by a pipeline or another merchant. This will provide all gas purchasers with improved access to all gas sellers whether or not the gas purchasers want a "no-notice" firm transportation service.

In brief, the Commission is making ten changes in Part 284. First, the Commission is revising Sections 284.8(a)(1) and 284.9(a)(1) to require firm and interruptible transportation services to be provided unbundled from firm and interruptible sales. This requirement also will be included as a condition on the blanket sales for resale certificates issued by this rule and discussed *infra*. Second, the Commission is adding Sections 284.8(b)(2) and 284.9(b)(2), which require a pipeline that offers firm and interruptible transportation services under Part 284 to provide those services on a basis that is equal in quality for all gas supplies whether purchased from the pipeline or another seller. Third, and fourth, the Commission is adding Sections 284.8(b)(3), (4), and (5) and 284.9(b)(3), (4), and (5) to require a pipeline to provide all shippers equal and timely access to certain information through the use of electronic bulletin boards, and to preclude any tariff provisions that would inhibit the development of market centers. Fifth, the Commission is amending Section 284.1 to define transportation as including storage. Sixth, the Commission is adding Section 284.242 to authorize and require open access pipelines to provide firm shippers on downstream pipelines with non-discriminatory access to capacity held by the downstream pipelines on upstream pipelines. Seventh, the Commission is adding Section 284.243 to authorize a new firm capacity reallocation program so that firm shippers can release unwanted capacity to those desiring capacity.

Eighth, as discussed above, the Commission is adding Section 284.8(a)(4) to require pipelines that make bundled sales on the effective date of this rule to provide a non-discriminatory "no-notice" firm transportation service. The "no-notice" transportation service as well as the other matters pertinent to open access transportation, will be discussed in Part VII.

Ninth, in order to further promote even competition among gas merchants, the Commission is adopting the straight fixed variable method of cost classification for the purpose of billing firm transportation customers unless the Commission provides otherwise. Under that method, all of a pipeline's fixed transmission and storage costs are billed in the pipeline's reservation charge.

Tenth, the Commission is issuing in this rule a blanket sales certificate to all pipelines so that they can make unbundled firm and interruptible sales on a comparable basis with unregulated merchants (*see infra*). This appears as a new Subpart J to Part 284.

Last, the Commission is also reemphasizing, as discussed fully below, the policy stated in Sections 284.221(g) and (h) of its regulations that pipelines allow shippers to have flexible receipt and delivery points.

The Commission believes that the above-described remedial approach will both improve the competitive structure of the natural gas industry, by putting pipelines, when acting as merchants, and other gas merchants on an even footing with respect to essential pipeline services and will maintain the ability of the pipeline system to provide reliable service when needed — regardless of the source of the gas. All of the above remedial

acts are discussed in detail below. In tandem with these changes the Commission has concluded that pipelines should be able to recover 100 percent of their prudently incurred costs associated with implementation of this rule. This is also discussed in detail, *infra.*

Based upon the extensive record compiled in this proceeding, the Commission believes that the above-described unified and comprehensive remedy will benefit all segments of the natural gas industry. To the extent members of the industry are currently facing an uncertain financial situation, the Commission believes that this rule will remove that uncertainty and create a regulatory framework that can adapt to changing market dynamics over the long-run. Indeed, this rule will establish an efficient gas market in which all participants are able to fashion the contractual arrangements — both long and short term — best suited to their needs. In short, they will be able to respond to their financial and commercial situation through the contracting process in an efficient gas market.

VII. ESSENTIAL ASPECTS OF, AND TERMS AND CONDITIONS FOR, OPEN-ACCESS TRANSPORTATION

A. Introduction

The Commission adopted Order No. 436 to prevent pipelines from discriminating in their choice of transportation customers in order to favor the pipelines' own sales services.[109] The Commission codified this anti-discrimination purpose in

109. Order No. 436, *supra* n.2 at p. 31,495 ("Examples of discrimination that the Commission finds to be undue or preferential within the context of self-implementing authorizations are refusals to transport for existing sales or non-fuel switchable customers and preference for affiliates.").

Sections 284.8(b) and 284.9(b) by requiring pipelines to offer their firm and interruptible transportation services "without undue discrimination" in the quality of service provided.[110] At the same time, the Commission recognized that pipelines need to impose "reasonable operational conditions" on their services to effectively manage their systems and Sections 284.8(c) and 284.9(c) permit this, provided the conditions are included in the pipeline's tariff.[111] In evaluating those operational conditions, the Commission dealt with many complex matters in its effort to ensure that there was no discrimination between the transportation embedded within the pipelines' bundled, city-gate, firm sales services and their open access firm transportation services.

Unbundling the sales and transportation components of the pipeline's city-gate, firm sales service changes the regulatory focus, but does not change the policy direction in which the Commission has been going. Before this order, the primary focus was on whether a pipeline's firm transportation service was comparable in quality to the firm transportation embedded within the bundled, city-gate, firm sales service.[112] After this

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110. 18 CFR 284.8(b) and 284.9(b).

111. 18 CFR 284.8(c) and 284.9(c).

112. *E.g.*, Tejas *supra*, at 1004 ("Without having first assessed the comparability of Texas Eastern's unbundled transportation and storage services, therefore, the Commission could not rationally conclude that the LDCs could take advantage of any alternative sources of gas."); United Gas Pipe Line Co., 55 FERC ¶ 61,330 at p. 61,974 (1991) ("United must specifically demonstrate that its transportation services and storage services available to firm transportation customers are comparable to the transportation and storage in its bundled service offered at market-based rates.").

order, the focus no longer will be on comparing the quality of two different pipeline services. Rather, the focus will be on ensuring that pipeline transportation of all gas supplies is performed on an equal basis under reasonable transportation terms and conditions that enable buyers to use open access transportation to maximize the benefits of a competitive wellhead natural gas market. To ensure equality of transportation service between gas sold by pipelines or their affiliates and gas sold by other gas sellers, the Commission's focus, after unbundling, must be on the quality of transportation service itself.

The Commission recognizes the need to analyze operational conditions in light of the pipeline's need to effectively manage its transportation system and its obligation to perform the new "no-notice" transportation service.[113] But the Commission must ensure that the operational terms and conditions devised to ensure effective system management do not give a competitive advantage to unbundled pipeline and pipeline affiliate sales. It is vital to ensure that gas purchasers have a viable, meaningful alternative to pipeline sales under a market-based pricing mechanism.

B. Transportation Equality and Other Principles

The Commission is amending Part 284 to require an open-access pipeline that offers firm and interruptible transportation services to provide those transportation services on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere. This requirement, embodied in new

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113. Various operational conditions which a pipeline might develop to manage its system are discussed in VII.D below.

Sections 284.8(b)(2) and 284.9(b)(2), will ensure that a pipeline, through a tariff provision or otherwise, does not give its own sales or the sales of an affiliate a preference over sales by other gas sellers in matters relating to Part 284 transportation. This equality principle will ensure that a pipeline cannot impose unreasonable restrictions on a shipper's ability to be served by other gas sellers. Any such restrictions would render transportation of gas sold by the pipeline or an affiliate superior in quality to transportation of gas of other merchants. Such a quality preference would result in undue discrimination under NGA sections 4 and 5 and is prohibited by the equality principle. As discussed above, after unbundling the focus must shift to ensure that the pipeline transports all gas supplies on an equal basis, not simply that the pipeline provides transportation of comparable quality for gas sold by other sellers with which it competes.

While a few commenters request the Commission to set forth uniform terms and conditions of service in the Commission's regulations,[114] the Commission concludes that such industry-wide specificity is not desirable in light of the differing configurations of pipeline systems and the differing needs of pipeline customers. Although the Commission will not develop generic, industry-wide, terms and conditions, the Commission will require that the terms and conditions that are developed must be applied in a non-discriminatory manner, must not give the pipeline or its marketing affiliate a competitive advantage, must not be unduly restrictive, and must be fair to all parties.

However, the Commission concludes that it should

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114. Fuel Managers Association, Appalachian Energy Group, Independent Petroleum Association of America, and American Paper Institute.

codify two other general principles in the regulations. The first is that nothing in a pipeline's tariff can inhibit the development of market centers or hubs. This appears in new Sections 284.8(b)(5) and 284.9(b)(5). While the Commission will not mandate market centers or hubs, it will prohibit tariff provisions that prevent their development.

The second general principle, embodied in Sections 284.8(b)(3) and (4) and 284.9(b)(3) and (4), is that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations.[115]

The precise nature of the information should be developed in the restructuring proceedings established by this order. At a minimum, the Commission will require the pipeline to timely inform all interested persons about the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, and whether the capacity is available from the pipeline directly or through capacity releasing.

To effect this requirement, those sections require all pipelines to use electronic bulletin boards. Since electronic bulletin boards have become standard industry-wide practice, the Commission has designed a rule that builds upon their use and sees no new burden in this requirement. Electronic bulletin boards in particular will be required to comply with the new capacity releasing requirement, discussed *infra*.

Pipelines must not provide preferential access to any users of the electronic bulletin board. They must permit users to

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115. See *infra* on capacity reallocations.

download files from the board, so their contents can be reviewed in detail without tying up access to the board. Pipelines must also keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records, which should be archived and reasonably accessible. Pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information. Information on the most recent entries should appear ahead of older information. In addition, electronic bulletin boards must be "user-friendly." The Commission urges pipelines to use software that allows extremely large files to be split into small parts for ease of use. Furthermore, the Commission urges pipelines to utilize software with on-line help, a search function that permits users to locate all information concerning a specific transaction, and menus that permit users to access separately each record in the transportation log, notices of available capacity, and standards of conduct information. The Commission may revisit these minimum general standards as needs warrant.

The Commission reiterates that, to ensure equality of service, pipelines must include all operating terms, conditions, and rules in their tariffs with the maximum amount of specificity possible. The Commission will focus more closely on compliance with this rule, codified in Sections 284.8(c) and 284.9(c), after unbundling because it is essential to an efficient open access transportation service that the pipelines impose only legitimate and reasonable operational conditions of which all shippers have had advance notice.

The Commission in Section 284.14 is requiring pipelines to have tariff provisions governing, at least, the following transportation matters. First, the pipelines must set forth in their

tariffs their methods for allocating aggregate receipt point capacity, individual receipt point capacity, mainline segment capacity, storage capacity, and delivery point capacity. Second, as discussed below, the pipelines must set forth in their tariffs provisions governing shipper flexibility in changing receipt and delivery points. Third, the pipelines must set forth in their tariffs their provisions concerning supply and capacity curtailments,[116] the scheduling of gas injections into the mainline and into storage, the scheduling of gas deliveries from storage and from the mainline, the setting and charging of penalties, balancing rights, and the instantaneous receipt and delivery of gas. Fourth, the pipelines must set forth in their tariffs their provisions under which they will provide the "no-notice" transportation service required by this rule. The Commission will further discuss the pipeline's "no-notice" transportation service below.

C. Capacity Reallocation

After reviewing the comments and reply comments, the Commission concludes that it is in the public interest for pipeline shippers to have the ability to reallocate unwanted pipeline capacity on a variety of bases to others seeking firm capacity. The only question is the best way to accomplish this on an industry-wide basis. The Commission concludes that this requires the adjustment of previously authorized capacity brokering and other capacity assignment (upstream capacity assignment and releasing) programs for two reasons. First, while the Commission has required that capacity be brokered or allocated on a nondiscriminatory basis,[117] the Commission no longer believes that it can adequately monitor capacity brokering

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116. See *infra*.

117. *E.g.*, Texas Eastern Transmission Corp., 48 FERC ¶ 61,248 at

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under existing certificates to ensure that all allocations are nondiscriminatory. Simply put, there are too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering as it now exists. Second, the Commission believes that the two new generic allocation of capacity programs it is adopting make the necessary adjustments to eliminate the potential for firm capacity holders to unduly discriminate in their assignment of capacity, and facilitate the development of the secondary transportation market.

The Commission, therefore, will not approve new individually authorized capacity brokering and other capacity assignment programs and is contemporaneously amending, by a separate order, the terms and conditions of existing capacity brokering and other capacity assignment certificates to conform to the capacity allocation regulations adopted by this rule. This is necessary to ensure that after the effective date of this rule all capacity reallocations are undertaken on the same basis on all pipelines. This will prevent any pipeline or firm shipper from achieving an undue advantage, or incurring an undue disadvantage, compared to firm shippers on other pipelines, from the working of the particular pipeline's capacity brokering program. Hence, the Commission is taking this action, in the above-noted order, to modify the terms of existing capacity brokering and other capacity assignment programs under NGA Section 5, as well as under the Commission's reserved right in those orders to modify a program, to ensure, as here, that they

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p.61,869-70 (1989), *clarified*, 48 FERC ¶ 61,378 (1989), *order on reh'g*, 51 FERC ¶ 61,170 (1990), *order on reh'g*, 52 FERC ¶ 61,273 (1990).

continue to be required by the public convenience and necessity.[118]

The Commission's treatment of "buy/sell" arrangements being considered in *El Paso Natural Gas Co., et al.*, Docket No. CP88-433-002, *et al.*, is related to the capacity brokering issue. Under those arrangements, an LDC will purchase gas in the production area from an end user or a merchant designated by an end user. The LDC will ship the gas on its own firm capacity and sell the gas to the end user at the retail delivery point. The Commission will not address buy/sell issues here but will do so in the *El Paso* docket. As explained in that order, under this rule, buy/sell arrangements should not be necessary because, under the capacity releasing requirement, firm capacity holders will be able to release unwanted firm capacity to persons seeking firm capacity. However, existing buy/sell deals can continue if the firm capacity holder does not give up its capacity in the restructuring proceeding as discussed below.[119] Similarly, buy/sell deals executed between the date of this order and the date

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118. *E.g.*, Texas Eastern Transmission Corp., 48 FERC ¶ 61,248 at p. 61,876 (1989).

119. In the NOPR, the Commission requested comment on "whether termination of capacity brokering will have a negative impact on independent power producers or qualifying facilities who may be receiving gas service for electric generating purposes through, so-called, 'buy/sell' arrangements." If so, the Commission asked whether it should "provide some form of grandfathering of existing transactions as part of the transitional phase contemplated under the Final Rule?" IV FERC Stats. & Regs. ¶ 32,480 at p. 32,545 (1991). The Commission believes that the steps taken in the final rule should avoid having a negative impact on IPPS or QFs using gas. To the extent this is not the case, interested persons should inform the Commission on rehearing of this rule.

the pipeline's capacity releasing mechanism goes into effect can continue if the firm capacity holder does not give up its capacity in the restructuring proceeding as discussed below. After a pipeline's capacity releasing mechanism goes into effect, no new buy/sell deals may be executed after that date and thereafter *all* allocations of interstate pipeline capacity must be done under the capacity releasing mechanism. When the pipeline's capacity releasing mechanism goes into effect, it must post on its electronic bulletin board for a reasonable period the price, terms and conditions, and names of the parties to all buy/sell deals existing on that date. All firm capacity holders who have executed buy/sell deals prior to that date must provide such information to the pipeline for posting on the electronic bulletin board. This posting is to make those arrangements public and not to allow other persons to make a better offer.

1. Upstream Pipeline Capacity

As discussed above, the Commission is requiring pipelines to unbundle the sales and transportation components of their bundled, city-gate, firm sales services to remedy the pipelines' undue advantage as merchants of gas over other merchants. As stated, one reason for the pipelines' advantage is that, as bundled merchants, they had access to more gas suppliers because of capacity held on upstream pipelines that connect with those gas suppliers.

The unbundling of sales and transportation will occur in many instances near the production area. However, in some instances, unbundling of a downstream pipeline's sales and transportation services will occur where it interconnects with an upstream pipeline which provides the downstream pipeline with access to the production areas. The downstream pipeline

will be able to use its transportation capacity on the upstream pipeline to acquire gas to make sales at the interconnection point to its (the downstream pipeline's) sales customers. The downstream pipeline would have an undue competitive advantage over other gas merchants because of the downstream pipeline's access to the capacity on the upstream pipeline. This situation would inhibit the goal of a competitive national market because the downstream gas purchasers would not have access to the production areas and gas merchants reached through the capacity held on the upstream pipeline by the downstream pipeline.

New section 284.242, therefore, provides that an open access upstream pipeline must permit a downstream pipeline to assign its firm transportation capacity (whether Part 284 or individually certificated) on the upstream pipeline on a non-discriminatory basis to the downstream pipeline's firm shippers. This rule also applies to contract storage capacity that the downstream pipeline holds on the upstream pipeline. In addition, the downstream pipeline will be required to assign its upstream firm transportation capacity (whether Part 284 or individually certificated) and its upstream firm contract storage capacity to its firm transportation customers to the extent necessary to provide capacity to those shippers that desire upstream capacity. All section 284.242 reassignments will be permanent. While this reassignment should occur initially in the restructuring proceedings,[120] section 284.242 will continue in effect after the restructuring proceedings to permit further reassignments of

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120. Section 284.242 capacity reassignment must be effectuated in the restructuring proceedings before downstream pipelines release their capacity under new Section 284.243 discussed below.

available upstream capacity held by downstream pipelines[121] to customers of downstream pipelines.

The NOPR proposed "that a downstream pipeline's capacity on an upstream pipeline should be considered as if that capacity were a mainline segment of the downstream pipeline . . . [and that a] downstream shipper's rights to [such] capacity would be determined under the method used by the downstream pipeline to allocate capacity on mainline segments[.]"[122] The Commission concludes that the issue of how to allocate capacity on upstream pipelines to shippers on downstream pipelines should be determined in the restructuring proceedings.

Texas Gas asks the Commission to clarify that the required allocation of capacity will not apply to interruptible capacity or capacity on intrastate pipelines or exchange transactions. The Commission clarifies that the requirement to allocate capacity on upstream pipelines to shippers on downstream pipelines does not apply to interruptible capacity held by downstream pipelines on upstream pipelines, to firm capacity held by downstream pipelines on intrastate pipelines, or to upstream exchange transactions.

Last, downstream pipelines subject to Subparts B or G of Part 284 will not be allowed to give up upstream pipeline capacity in the restructuring proceedings except under new Section 284.242. This exception is necessary to ensure that firm

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121. If the downstream pipeline releases the capacity under new section 284.243, the capacity would be assignable, however, any prior release would remain in force.

122. IV FERC Stats. & Regs. ¶ 32,480 at p. 32,551 (1991).

customers of downstream pipelines have the first opportunity to gain access to capacity, on upstream pipelines, held by the pipeline to which the customers are directly connected. If the customers of downstream pipelines do not want the capacity on upstream pipelines, the downstream pipeline can release its capacity on upstream pipelines through the capacity release provisions of new Section 284.243, discussed in the next section. If the downstream pipeline is unable to shed unwanted upstream capacity through releasing, it can seek to recover costs associated with the "stranded" upstream capacity as a transition cost as discussed, *infra*.

2. Voluntary Reallocation of Firm Transportation Capacity

The upstream pipeline capacity assignment requirement will provide customers of downstream pipelines with capacity needed on upstream pipelines. This will afford those customers with additional flexibility in their choice of gas sellers. However, this type of assignment is only one aspect of an adequate capacity assignment program. The Commission believes that it is necessary to adopt a program that contains several important elements of capacity brokering so that shippers can reallocate unneeded firm capacity on a variety of bases. Capacity reallocation will promote efficient load management by the pipeline and its customers and, therefore, efficient use of pipeline capacity on a firm basis throughout the year. Because more buyers will be able to reach more sellers through firm transportation capacity, capacity reallocation comports with the goal of improving nondiscriminatory, open access transportation to maximize the benefits of the decontrol of natural gas at the wellhead and in the field.

Appendix B

Accordingly, the Commission is adding a new Section 284.243 to *require* all open access pipelines to provide a capacity releasing mechanism through which shippers can voluntarily reallocate all or part of their firm transportation capacity rights to any person who wants to obtain that capacity by contracting with the pipeline. Shippers may reallocate their firm transportation capacity (whether Part 284 capacity or individually certificated capacity) only under Section 284.243.

This capacity releasing mechanism would allow firm capacity holders to permanently or temporarily release some or all of their capacity through the pipeline to be reassigned to persons desiring capacity. The capacity releasing mechanism would afford buyers and sellers of firm capacity with one place to shop to ensure that firm capacity is used as efficiently as possible.

Capacity releasing will operate as follows. The firm capacity holder will inform the pipeline that it wants to release capacity on a permanent or temporary basis, the specific quantity to be released, the period of time, and any other conditions of the release. For example, the releasing customer might state that it will release a specified amount of capacity only so long as the temperature remains above a specified degree. That is, the firm shipper may release firm capacity on an interruptible basis. In addition, the releasing customer can bring to the pipeline for posting a pre-arranged deal for releasing capacity. If no better offer is received,[123] the pipeline *must* contract with the replacement shipper found by the releasing customer. If a

123. The Commission will not define what constitutes a better offer because of the wide variety of potential releasing scenarios. The parties must consider in the restructuring proceedings the issue of what constitutes a better offer.

better offer is forthcoming, the pipeline must give the replacement shipper found by the releasing customer an opportunity to match the better offer. If the replacement shipper matches the better offer, the pipeline must contract with the replacement shipper found by the releasing customer. If the releasing customer's designated replacement shipper does not match the better offer, the pipeline must contract with the person who made the better offer.

The pipeline must immediately post the capacity releasing information on its electronic bulletin board for a reasonable period of time during which applicants for capacity can agree to the releasing customer's terms and conditions.[124] As discussed below, the pipeline may take other action to market any released capacity.

The pipeline will be required to resell that capacity under Part 284 to the applicant meeting the releasing customer's specifications. The replacement shipper must, of course, satisfy all of the pipeline's tariff provisions governing shipper eligibility before it can contract with the pipeline for the capacity. Unless the pipeline otherwise agrees (such as where there is a permanent reallocation of annual capacity), the releasing customer will remain liable on its contract but will receive a credit against its bill for the capacity resold. The pipeline itself should be indifferent to the substitution because its total contract demand will remain unchanged.[125]

Once the replacement shipper enters into a contract with the pipeline, the replacement shipper becomes a shipper like

124. For example, the pipeline should alert shippers in advance of the conditions under which the releasing shipper may recall released capacity.

125. See *infra* on interruptible transportation capacity.

any other shipper and is subject to the pipeline's operational provisions as stated in its tariff. In addition, the replacement shipper as a shipper can also release its capacity through the pipeline's capacity releasing program. The pipeline's tariff must have provisions that clearly delineate the rights and obligations of such secondary releasing shippers and those of the primary releasing shipper.

The NOPR would have allowed the pipeline to sell its own uncommitted capacity prior to reselling that of a releasing customer. The new rule requires the pipeline to post its available capacity and terms and conditions on its electronic bulletin board. Potential purchasers of capacity will then be able to choose from among the pipeline and the releasers the service that best suits their needs.

The Commission will permit the pipelines and their customers, and other interested participants, to determine the details of a pipeline's capacity releasing program in the individual restructuring proceedings. For example, the NOPR proposed a seven day open season for applicants to agree to the releasing customer's terms. However, the Commission is not mandating a particular time period for an open season to avoid inhibiting needed flexibility. The participants in the restructuring proceedings may determine what is a reasonable period and may, for example, decide that different periods are needed for different types of released capacity. In addition, the participants should determine the pipeline's compensation for the capacity releasing program. This recompense would, of course, consist of a reasonable administrative fee to cover the pipeline's out-of-pocket expenses in connection with establishing and operating the capacity releasing program.[126]

126. *See* Inquiry Into Alleged Anticompetitive Practices Related to (Cont'd)

Moreover, as a further incentive to effectuate capacity releases, the Commission will permit the pipeline to be compensated when it actively markets released capacity.[127] The participants in the restructuring proceedings must determine the appropriate amount of the pipeline's recompense (*e.g.*, a sharing of proceeds) when it takes affirmative action to market the released capacity, beyond posting the information on the bulletin board, and finds a replacement shipper. The releasing shipper will receive a net credit against its reservation fee for the proceeds of the resale minus the pipeline's recompense. The participants should determine what actions merit compensation. Even though the pipelines are required to post the releasing shipper's offer to release capacity, this recompense will give the pipelines a financial incentive to promote efficient capacity reallocations beyond simply posting capacity availability and to benefit releasing shippers via the credit to their bills. Of course, the pipeline will not be compensated if it does not find the replacement shipper, such as where the releasing shipper had a pre-arranged deal as discussed above, or where someone accepts a posted offer without the pipeline finding that new shipper. It is only appropriate for the pipeline to receive compensation when it makes an extra effort to market the released capacity, for example, when it combines two or more packages of released capacity into one, more attractive package. The administrative fee would apply regardless of whether a replacement shipper takes the released capacity since it is

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Marketing Affiliates of Interstate Pipelines, Order No. 497-A, 54 FR 52781 (Dec. 12, 1989), FERC Stats. & Regs. [Regulations Preambles] ¶ 30,868 at p. 31,602 (1989).

127. *E.g.*, Initial Comments of Michigan Consolidated Gas Company.

designed to recover the pipeline's out-of-pocket expenses in administering the capacity releasing program.

The pipeline and the participants must devise in the restructuring proceeding methods for dealing with the circumstance where more than one applicant meets the releasing shipper's price and other specifications or where an applicant makes a counter offer.

The main difference between capacity brokering as it now exists and the new capacity releasing program is that, under capacity brokering, the brokering customer could enter into and execute its own deals without involving the pipeline. Under capacity releasing, all offers *must* be put on the pipeline's electronic bulletin board and contracting is done directly with the pipeline. Nonetheless, the releasing shipper may search for someone to take its capacity both before and after the capacity is put on the electronic bulletin board. However, as stated, a capacity releasing deal cannot be consummated until after it is posted.

The main objection by commenters[128] is that pipelines will have no incentive to effect the releasing of capacity. However, the rule requires the pipeline to establish and operate a capacity releasing program. The pipeline must transfer released firm capacity to willing buyers of that capacity. Because the program will be operated in accordance with the pipeline's open-access transportation tariff, the pipeline may not refuse to provide the requested service if the shipper meets the pipeline's applicable

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128. *E.g.*, Department of Energy, Public Service Commission of the State of New York, Public Utilities Commission of the State of California, United Distribution Companies, and Northern Indiana Public Service Company.

tariff conditions. In addition, as stated above, the Commission is permitting pipelines to market released capacity and to be compensated if they take affirmative action to market the released capacity and find a replacement shipper, beyond posting the information on the bulletin board. Hence, the Commission concludes that pipelines will not act to inhibit capacity releasing.

Of course, the pipeline must continue to sell all its available firm or interruptible capacity. The pipeline must do this by putting the terms and conditions on the electronic bulletin board. It is up to customers to decide if they want the pipeline's uncommitted firm capacity, the released capacity or interruptible capacity.[129] In addition, any change in the level of the pipeline's interruptible volumes due to the releasing program will be accounted for in the pipeline's next rate case when projecting interruptible volumes.

The Commission's adoption of capacity releasing for all pipelines overrules all orders issued subsequent to Order No. 436 to the extent they prohibited capacity assignment.[130]

The regulations require the pipeline to allocate released capacity to the person offering the highest rate not over the maximum tariff rate the pipeline can charge to the releasing shipper. This means that the persons seeking to obtain the released capacity can offer up to the pipeline's filed maximum rate for the service received by the releasing shipper. For

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129. For example, a customer might want annual interruptible capacity rather than firm capacity on a limited basis.

130. *E.g.*, El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,065-66 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987) and Texas Eastern Transmission Corp. 37 FERC ¶ 61,260 at p. 61,684 (1986).

example, if a releasing shipper wants to release firm capacity from the Gulf of Mexico to New York City, the maximum rate would be the pipeline's maximum rate for service from the Gulf of Mexico to New York. That is the maximum rate even if a replacement shipper only wants the releasing shipper's capacity to move gas for a shorter haul (*e.g.*, from the Gulf of Mexico to Atlanta, Georgia).

In addition, the Commission is issuing, to the extent necessary, in the new regulations, a limited blanket certificate of public convenience and necessity under NGA Section 7 to all shippers holding firm capacity rights on pipelines to allow those shippers to release their capacity pursuant to the new capacity releasing program. The purpose of this certificate is limited to allowing those shippers to release capacity to the pipeline as described above. This certificate does not authorize shippers to broker or assign or release capacity as under prior certificates. Rather, new Section 284.243 permits the Commission to ensure that all releases are on a nondiscriminatory basis pursuant to new Section 284.243. Moreover, this will make it clear that the Commission has sufficient jurisdiction to take appropriate enforcement action if capacity is not released on a nondiscriminatory basis. As stated above, the pipeline must contract with, and bill, the replacement shipper.

Last, as stated above, the Commission is amending existing capacity brokering and other capacity assignment programs to conform to the capacity allocation regulations adopted by this rule. Capacity brokering or other assignment arrangements in effect on the effective date of a pipeline's capacity releasing program under new Section 284.243 of the Commission's regulations can continue, provided the broker or assignor does

not give up its capacity in the restructuring proceeding as discussed *infra.* In addition, on the effective date of the pipeline's capacity releasing program, the pipeline must contract with the holder of the brokered or assigned capacity as it would with a replacement shipper at the same price and terms and conditions of the contract between the broker or assignor and the holder of the brokered or assigned capacity. The pipeline must immediately post on its electronic bulletin board for a reasonable period the price, terms and conditions of, and names of the parties to, all such arrangements. This posting is to make those arrangements public and not for allowing other persons to make a better offer.

D. "No-Notice" Transportation Service

As discussed above, the Commission is adding Section 284.8 (a)(4) to its regulations to require pipelines to provide a "no-notice" firm transportation service if they are providing a "no-notice" bundled, city-gate, firm sales service on the effective date of this rule. The Commission expects the pipelines and all interested participants to craft in the restructuring proceedings the operating conditions needed to ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties. This "no-notice" service will enable pipeline customers to continue to receive unnominated volumes to meet unexpected requirements caused, for example, by unexpected changes in temperature. Thus, pipeline customers will be able to receive varying volumes of gas to meet their fluctuating needs during a twenty-four hour period. So, for example, constant rate of flow requirements would not apply to prohibit delivery on demand throughout the

day up to a customer's daily firm entitlement under this service. The pipeline, however, could charge reasonable imbalance penalties, for example, monthly imbalance penalties.

The pipelines must include in their tariffs filed as part of their restructuring filings, and maintain in their tariff after implementation of their restructuring proposal, all operating conditions germane to the provision of a "no-notice" firm transportation service. In addition to knowing those operational conditions, it is important for firm shippers to be aware of the component costs attributable to the "no-notice" transportation service. Only then will pipeline customers be able to make an informed choice about, for example, whether to elect "no-notice" transportation or the pipeline's other open-access, firm transportation service. The pipeline's customers need to know the differences between various services and the costs associated with those differences. Hence, the pipelines must, in the restructuring proceedings, indicate how they derived their "no-notice" and other firm transportation rates. This requires the pipelines to prepare workpapers detailing, among other things, the discrete elements of the "no-notice" transportation service rates, such as the cost of any system storage or imbalance services included within a rate. Furthermore, the pipelines must separately identify those cost components in their rate schedules filed as part of their *pro forma* tariff sheets in their restructuring filings and in future tariff filings. The Commission's aim is for pipeline customers to be able to rationally choose from a menu of pipeline services. The pipeline customers may elect "no-notice" transportation or decide to purchase other open access transportation or other distinct services, such as contract storage or, if offered, an imbalance management service.

It is important to note that this required new "no-notice"

transportation service differs from an "agency" service. The "no-notice" transportation service is a service where the pipeline customer can receive its gas on demand as discussed above. That gas may be purchased from the pipeline or from any other gas seller. The "agency" service is a service where the gas purchaser gives an agent (either the pipeline in its role as gas seller, or another gas supplier) the right to act on its behalf to arrange for pipeline services to deliver the gas. The "agency" service does not ensure "no-notice" service by the pipeline as does the new "no-notice" transportation service to be provided in addition to traditional open-access, firm transportation service. Rather, the "agency" service is a service where the gas purchaser gives an agent the right to act on its behalf in fulfilling its obligations with respect to the pipeline services elected by the gas purchaser. For example, the gas purchaser could authorize an agent to nominate its injections into the pipeline under the pipeline's traditional open-access firm transportation service or to be responsible for responding to operational flow orders to inject gas into the pipeline under the "no-notice" transportation service. However, an agent, such as a marketer, could guarantee a "no-notice" service but, unless the gas is shipped under the pipeline's "no-notice" transportation service, the agent, and not the pipeline, would be responsible for providing the "no-notice" service.

The Commission believes that all pipelines, with appropriate operational conditions, can provide a "no-notice" firm transportation service. This is because the Commission envisions the pipeline managing its unbundled system in a similar manner to its management of its bundled system, except that the place where title to gas transfers will be upstream. Indeed, at the January 22, 1992 technical conference, the pipeline industry representatives indicated that the pipelines

could perform a "no-notice" firm transportation service provided the pipelines retained adequate control of the use of their facilities.[131]

The Commission will not impose or forbid any particular operational conditions at this time. The pipelines and interested participants need the flexibility to explore all aspects of how the pipelines can provide this service in light of the individual configurations of the pipeline systems. Of course, the operational conditions must be devised and implemented on a non-discriminatory basis for all shippers. Simply put, the Commission will not allow any operationally related tariff provision to undermine the quality of unbundled services the pipeline will be required to provide or to give a competitive advantage to the pipeline as a seller or to its marketing affiliate.

The Commission is requiring the pipelines to provide a "no-notice" transportation service as part of its remedy in connection with concluding that the pipelines' bundled, city-gate, firm sales service contravenes NGA Section 5. However, some commenters contend that the Commission's action under NGA Section 5 violates NGA Section 7 because the Commission lacks the authority to revoke, suspend, or adversely modify an issued and accepted certificate.[132]

NGA Section 5 expressly authorizes the Commission to find that any "rate, charge, or classification" or "any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential,"

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131. Technical Conference Tr. 36-38.

132. *E.g.*, PEC Pipeline Group, Associated Gas Distributors, and Baltimore Gas and Electric Company.

and requires the Commission to determine and fix the "just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." The courts have rejected contentions that Commission action under NGA Section 5 is an unlawful revocation or modification of a certificate of public convenience and necessity under NGA Section 7.[133] As a court noted in an analogous situation to that presented here:

> Section 7, which vests in the Commission control over the conditions under which gas may initially be dedicated to public use, does not guarantee that the initial terms of that service will never change. [134]

Of course, "the LDC's entitlement and the pipeline's obligation [have] a legal existence independent of the contract and persist until the Commission issues formal approval of abandonment."[135] Here, the Commission is altering existing bundled sales contracts but is retaining both the LDC's entitlement and the pipeline's service obligation with respect to firm sales, if the LDC and the pipeline agree upon the price for

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133. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n.9 (D.C. Cir. 1985), *citing*, Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 389 (1959) *cert. denied*, 476 U.S. 1114 (1986); Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 746 (5th Cir. 1987); *cert. denied*, 484 U.S. 1005 (1988).

134. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n. 9 (D.C. Cir. 1985).

135. Associated Gas Distributors v. FERC, 824 F.2d 981, 1013 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

gas, and the firm transportation of gas to the city-gate under no-notice transportation service. Conversely, in the absence of an agreement pursuant to the procedures established by this rule, a pipeline's sales service obligation will cease as of the effective date of the tariff sheets filed in compliance with this rule. See discussion, *infra,* in Section IX. The Commission is changing one contract under one certificate for firm sales and embedded transportation into two contracts and two blanket certificates for firm sales and firm transportation. The existing bundled, city-gate service will be supplanted as of the effective date of the tariff sheets filed to comply with this rule. The terms under which the pipelines sell and transport gas are changed. The pipelines' certificates for individual service are, in essence, merged into or subsumed within the pipelines' blanket certificates. Thus, depending on the outcome of the negotiations, any new pipeline sales service obligation will be defined by the terms of the new contractual relationship entered into as a result of the restructuring proceeding. The pipelines' service obligation under the blanket sales certificates and contractual arrangements for unbundled sales are discussed below in Section IX.A, *infra.*

The Commission is giving pipeline customers as part of its remedial action, the right to reduce their unbundled firm sales entitlements in whole or in part as a transition to the market-based gas pricing regime. This will enable the pipeline's firm sales customers to freely negotiate the quantity and price of supplies purchased from the pipeline or other gas suppliers. Those customers will, therefore, be able to take advantage of all opportunities for long-term sales contracts in a competitive market. However, this remedial action does not revoke the pipelines' authority to sell gas. It merely means that the pipelines must compete to retain their business. Last, while "the Commission has plenary authority to limit or to proscribe

contractual arrangements that contravene the relevant public interests,"[136] the Commission emphasizes that a purpose of this rule is to create a regulatory environment whereby gas purchasers and gas sellers can structure their relationships as much as possible by private commercial contracts after the initial transition.

The Commission's analysis of the comments yields two interrelated operational concerns about unbundling and the "no-notice" firm transportation service. The first concern is with keeping the pipeline operational at the pressures required to provide an efficient and reliable transportation service. The second concern is that the pipeline have adequate supplies to deliver on demand. For example, CNG Transmission Corporation expressed concern about losing throughput capacity because of the impact of unbundling on deliveries through displacement.[137] Because the pipeline is operating as a transporter, its ability to effectively manage its system will depend in part on its shippers injecting gas into the mainline (packing the line) and into storage at the right place and time. While the pipeline and its shippers (or their suppliers or agents) may be able to achieve what is needed through communication, cooperation, coordination, and compromise, it may be necessary for the pipeline to retain compulsory powers where it dictates to shippers where and when to act by, for example, operational flow orders. All shippers

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136. Permian Basin Area Rates, 390 U.S. 747, 784 (1968).

137. Initial comments at 20. CNG states that "[d]isplacement occurs whenever gas supplies are recovered at one point on the system for redelivery at another point without a physical flow of that amount of gas along a continuous path between the two points." *Id.* n. 15. For example, CNG is concerned about its ability to ensure reliability with its current storage in the absence of its bundled sales services.

must recognize that the action or nonaction by a single shipper may affect a pipeline's ability to serve all other shippers.

Several additional matters deserve discussion. First, the Commission recognizes that the pipeline must be able to control the operation of the system facilities, such as operation of the compressors and the performance of maintenance. The pipeline may need to enter into agreements with gas suppliers where they balance injections of their shippers and provide predetermined allocation agreements. The pipeline may have to direct shippers to inject gas at particular supply inputs at particular times to keep the line appropriately packed.[138] The pipeline may have to retain *some* storage capacity or have the right to borrow gas from contract storage, or both, to keep the system in balance and to provide this "no-notice" service. [139] The pipeline may have to impose reasonable limitations on the use of storage, including conditions of injection and withdrawal, and may have to designate shippers to particular storage facilities. The pipeline and its shippers need to fashion reasonable, yet effective, methods such as penalties to deter shipper behavior inimical to the welfare of the system and other

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138. For example, at the January 22 technical conference, Arkla Energy Resources emphasized that on web-like systems, the pipeline needs to retain operational control to maintain the bidirectional flow necessary in order to maintain its peak capacity. Technical Conference Tr. 71-73.

139. As a general matter, gas in storage can be analogized to money in a bank. The customer injecting gas into storage is acting like a depositor putting money into a bank. The customer, as a "depositor", may withdraw its gas from the pipeline when it wants. (Of course, the customer's right to withdraw gas from storage is subject to operational constraints.) But the pipeline, just as a bank, may use the "deposited" gas to serve another customer in the meantime.

shippers. The pipeline and its shippers and interested participants may develop reasonable mechanisms to permit the borrowing of gas of one shipper by another shipper so that the pipeline can make deliveries on demand. For example, an interruptible transportation customer with gas in the system may have to allow the gas to be delivered to an LDC to meet its needs when the temperature drops unexpectedly. Once again, the Commission will require the pipeline to devise and implement all operational provisions on a nondiscriminatory basis for all shippers, without diluting the quality of unbundled services that must be offered or creating an advantage to the pipeline as seller or to its marketing affiliate.

The discussion above indicates some of the complex matters that need to be addressed by the participants in the restructuring proceedings. The Commission expects all interested parties to participate in tailoring the appropriate operational features of the pipeline's tariff. However, the Commission recognizes that those provisions may vary from pipeline to pipeline. Moreover, each provision will be scrutinized by the Commission in the compliance filing to ensure that the proposal does not, in any way, undermine the quality of transportation principle set forth above.

The requirement that a pipeline provide "no-notice" transportation service will enable a customer to receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices. Hence, the customer will have the "best of both worlds" — reliable service and competitively priced gas. The following scenario depicts how this would happen.

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Upon unbundling, the pipeline's former bundled, city-gate, firm sales customer will be entitled to purchase gas from the pipeline or from another gas supplier and to ship its gas under the new "no-notice" firm transportation service. The customer can also appoint its gas seller, whether it is the pipeline or another gas supplier, to act as its agent in dealing with the pipeline. The agent would be responsible for making all arrangements with the pipeline necessary to deliver the gas to the customer. For example, since it will be up to the customer to ensure that its supplies are capable of physical delivery, the customer or its agent would have to inject gas into the mainline and into its contract storage in conformance with the pipeline's tariff. The pipeline will then be obligated to deliver the customer's gas up to its daily contract entitlement, without penalty, even if this is above the scheduled amount. Thus, the customer's ability to just "turn on the valve," in layman's parlance, would be the same as its current ability under bundled service. This will allow the customer to meet the demand of its system as it has historically done, for example, when the weather suddenly turned cold.

Of course, the pipeline could include in its rates for the "no-notice" transportation service the costs associated with performing this service. For example, it could include the costs of managing imbalances through the use of contract gas in storage. The pipeline could also offer different daily imbalance management options based on a customer's desired tolerance above expected scheduled quantities and allowed tolerances.

The Commission concludes by reminding the industry that it is in the nation's and the industry's interest for them to arrive at legitimate and effective operational conditions which keep gas flowing and deliverable when and where needed and at the same time do not unreasonably inhibit the meeting of gas

purchasers and gas sellers in a competitive market place. Again, the Commission will scrutinize all proposed operationally-related tariff provisions to ensure that they are devised and implemented on a nondiscriminatory basis for all shippers.

E. Storage

As discussed above, the Commission is requiring pipelines to unbundle the sales and transportation components of their bundled, city-gate, firm sales services to remedy the pipelines' unfair advantage as merchants of gas over other merchants. As stated, a reason for the pipelines' advantage is that, as bundled merchants, they have superior access to storage facilities. This is because, at present, an open access pipeline must make system storage available to firm shippers only on a nondiscriminatory basis to assure open access firm transportation service.[140] The Commission has not required open access pipelines to make storage available on an open access contract basis so that shippers may store their own gas.[141]

The pipelines' superior rights with respect to access and control of storage provide them with several advantages over other gas merchants with no access to storage for their gas. First,

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140. Order No. 436, *supra* n.2, at p. 31,507. System storage includes facilities owned and used by the pipeline to store its own gas for operational reasons such as for balancing or for use in lieu of transportation capacity.

141. Some open access pipelines have applied for blanket certificates to provide firm and interruptible open access storage services. *E.g.*, Texas Eastern Transmission Corp., 53 FERC ¶ 61,424 (1990); Northwest Pipeline Corp., 50 FERC ¶ 61,341 (1990) and ANR Pipeline Co., 46 FERC ¶ 61,339 (1989), *reh'g and clarification granted in part and denied in part*, 49 FERC ¶ 61,046 (1989).

the pipelines can use storage to implement seasonal supply management where they purchase gas during offpeak periods. This enables the pipelines to cut gas costs by buying gas when it is less costly during offpeak periods. Second, the pipeline can use storage as a supplement to transmission capacity. This occurs when mainline transmission capacity is less than the pipeline's firm obligations, with the difference delivered out of downstream storage close to the pipeline's market areas. Last, pipelines can use storage to maintain a constant flow of gas by taking supplies from, or diverting gas to, storage. This enables them to manage their system in response to rapidly changing customer demands for gas. The above-described uses of storage give the pipelines an unfair advantage over other gas sellers because non-pipeline shippers do not have the flexibility to provide fully a sales service which meets gas purchasers' peak needs.

The Commission's unbundling of pipeline sales and transportation services means that pipelines with downstream storage will need it *only* to fulfill their obligations with respect to system management (load balancing) and "no-notice" transportation. Because storage is now defined as transportation, under Section 284.1(a), which must be unbundled from sales, the pipeline itself may not retain, or hold, any storage capacity downstream of the place where it unbundles in connection with the providing of any of its own sales services. Hence, the pipelines with downstream storage should have storage available to sell to transportation customers on an open access, nondiscriminatory, contract basis. This will enable open access transportation customers to buy gas and store it for future use. This will enable all shippers to more effectively manage their gas supply and procurement programs.

In addition, shipper access to upstream storage is an

important factor in securing equality for all gas suppliers. For example, this storage is valuable to gas purchasers that want to buy gas off peak at cheaper prices and store it for later use. Preventing access to upstream storage gives the pipelines, as sellers, an undue competitive advantage over other gas merchants and conflicts with the goal of open access to maximize the benefits of competition by requiring all gas supplies to be treated and transported on equal terms.

The Commission is amending Part 284 to require an interstate pipeline to offer access to its storage facilities on a firm and interruptible open access contract basis as part of its open access transportation. This is accomplished by amending Section 284.1(a) of the Commission's regulations to define transportation as including storage. As amended, Section 284.1(a) would read: " 'Transportation' includes storage, exchange, backhaul, displacement or other methods of transportation." Storage, therefore, would be included within the nondiscriminatory access and other requirements of Part 284 for interstate pipelines.[142] Intrastate pipelines would be permitted, but not required, to offer open-access, contract storage under Subpart C of Part 284 of the Commission's regulations. The Commission is also making minor conforming changes to the existing reporting requirements contained in Part 284. Pipelines providing blanket open-access storage services under Part 284 will be required to submit reports to the Commission after the end of each injection and withdrawal season, as is currently required of pipelines holding blanket storage certificates. However, the Commission will not require pipelines to file duplicative self-implementing transaction reports.

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142. *E.g.*, storage rates would be designed pursuant to Part 284 as amended by this order. See also n.141, *supra* for examples of previously certificated open-access storage services.

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Pipelines would have to provide access to storage on a firm and interruptible basis for all shipper gas without regard to the seller in a manner that is not unduly discriminatory. The pipeline would be required to offer the open access storage on a basis that is unbundled and not in any way tied or linked to the storage customer's purchase of any particular type of sales service. However, the pipeline may offer both transportation and storage services as part of the service to perform its "no-notice" transportation service required *supra*, but the pipeline must also make storage available on a stand-alone basis. Of course, a shipper purchasing open access contract storage would be responsible for arranging to put its own gas in its firm storage space so that it can be withdrawn when needed.

Commenters raise concerns about the allocation of storage capacity, the pipelines' needs to retain storage capacity for system management, the rights of current holders of contract storage capacity, and whether converting customers under the new regulations should have priority for storage capacity.[143]

The Commission will not impose a generic allocation method for storage capacity. The only requirement imposed in the regulation is that storage capacity must be allocated on an even, nondiscriminatory basis among all shippers without regard to the seller of the gas. For example, the pipeline may hold an open season for initial allocation of storage capacity. Or, storage can be allocated on a pro-rata basis. This should be addressed in each restructuring proceeding. With respect to storage capacity *upstream* of the place of unbundling, the pipeline will be able

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143. *E.g.*, Citizens Gas and Coke Utility, Gas Company of New Mexico, Long Island Lightning Company, New England Gas Distributors, Peoples Natural Gas Company, Washington Gas Light Company, and INGAA.

to continue to retain some of that capacity for its own use as a seller. The allocation of this capacity between the pipeline, for use to make sales, and others, of course, must be done on a non-discriminatory basis and the costs associated with the upstream storage capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream storage capacity (*e.g.*, injection and withdrawal requirements).

Any allocation of storage capacity, however, must take into account pipeline capacity needs for load balancing and system management and the need to reserve some level of storage capacity for the pipeline or for shippers in connection with the pipeline's "no-notice" transportation service. The reservation of storage capacity for these transportation services is different from the pipeline's reservation of storage capacity to make sales. The reservation of storage capacity for transportation functions should be addressed in the restructuring proceedings.

All current holders of contract storage capacity will retain that capacity under current contractual provisions and are not subject to the pregranted abandonment provisions discussed, *infra*. However, as stated above, firm storage capacity held by downstream pipelines on upstream pipelines must be made available to the downstream pipeline's firm shippers under new Section 284.242. Moreover, the downstream pipelines, like all holders of firm storage capacity, can release their upstream storage capacity under Section 284.243.

If the pipeline has storage capacity remaining after it has sold contract storage and retained any system storage needed for system management and load balancing purposes to perform

its "no-notice" transportation service, or to make sales upstream of the unbundling point, the pipeline can seek to recover costs associated with the "stranded" storage capacity as a transition cost, as discussed, *infra.*

Associated Gas Distributors argues that "the final rule should expressly provide that interruptible storage capacity should *not* be made available when that capacity is already held by another shipper."[144] The Commission concludes that pipelines should not limit the availability of interruptible storage unless it is shown in a restructuring proceeding that a particular limitation is operationally warranted on a particular pipeline system.

The NOPR proposed to amend Section 284.1(a) only with respect to interstate pipelines. Houston Pipe Line Company asks that the final rule be clarified to make clear that intrastate pipelines, while not required to provide open access storage service, are nevertheless permitted (or are not denied the opportunity to offer) NGPA Section 311(a)(2) storage services. The Commission has clarified this by amending Section 284.1(a) so that it applies to both interstate and intrastate pipelines.

F. Market Centers and Pooling Areas

1. Market Centers

The Commission is adopting this rule in order to facilitate the meeting of gas purchasers and gas sellers in a national gas market.[145] Market centers may, in certain areas, create additional

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144. Initial Comments at 21 (emphasis in original).

145. *See* the discussion of market centers in Importance of Market

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meeting places for gas purchasers and gas sellers. These inter-pipeline market centers would allow gas from production areas attached to different pipelines to meet where the pipelines intersect to create a market for gas purchasers from different market areas. The Commission believes that market centers should develop naturally and, therefore, will not mandate market centers. However, as stated above, the Commission is requiring in new Sections 284.8(b)(5) and 284.9(b)(5) that there must be nothing in a pipeline's tariff that inhibits the development of market centers.

In addition, as discussed below, the Commission is amending its Part 284 regulations to require pipelines to permit shippers to receive gas into the system and to deliver gas from the system anywhere receipt and deliveries are possible. This should facilitate both the development of market centers and the use of capacity releasing.

2. Pooling Areas

The Commission also believes that the meeting of gas purchasers and gas sellers can be facilitated by the creation of production area pooling areas on individual pipelines. Production area pooling areas may facilitate the aggregation of supplies by all merchants. The pooling areas may either be places where title passes from the gas merchant to the shipper or they may be places where aggregation and balancing and penalties are determined ("paper" pooling areas). The Commission will not mandate pooling areas, but will not permit actions that inhibit their development.

(Cont'd)
Centers, Office of Economic Policy, FERC (Washington, D.C.), August 21, 1991.

At whatever place unbundling occurs,[146] and whether or not a pipeline establishes pooling areas, the Commission believes that pipelines should consider entering into "operational balancing agreements" with other gas merchants to allow them to balance, in the aggregate, for all of their gas purchasers shipping on the pipeline. The Commission also wants the pipelines and their customers and interested parties to consider in the restructuring proceedings the need for appropriate equipment to accurately monitor and measure injections into the system on a timely basis. It may not be cost-effective on some pipeline systems to install the necessary equipment. In those cases, the pipelines should consider allowing other gas merchants to provide the pipeline with pre-determined allocation plans for the merchant's gas. The pipeline should report on this matter in its restructuring filing.

G. Flexible Receipt and Delivery Points

Section 284.221(g) of the Commission's regulations gives pipelines the authority to permit flexible receipt points for receipts of gas volumes into their systems.[147] In implementing that section, the Commission has required that firm shippers must have flexibility in changing firm receipt points and in using all available receipt points on an interruptible basis.[148] This flexibility includes the right to bump interruptible shippers on reasonable notice.[149]

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146. The point of unbundling should be located as far upstream as possible.

147. 18 CFR 284.221(g).

148. Northwest Pipeline Corp., 46 FERC ¶ 61,106 at p. 61,428 (1989).

149. Williams Natural Gas Co., 56 FERC ¶ 61,281 at p. 62,095 (1991).

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Section 284.221(h) of the Commission's regulations, also promulgated by Order No. 436, gives pipelines the authority to permit flexible delivery points for deliveries of gas volumes from their systems.[150] However, the Commission subsequently concluded that, in most cases, flexible delivery points were inconsistent with the Commission's requirement of identification of the recipient of the gas in each transaction.[151] The Commission's concern was that flexible delivery points could lead shippers to broker capacity and thereby abuse the first come, first served principle for allocating mainline capacity. However, in *Columbia Gas Transmission Corp.*, the Commission permitted Columbia to institute flexible delivery points because Columbia's firm sales customers had conjunctive billing rights where the customer could accept delivery at multiple delivery points.[152] Recently, in *Transwestern Pipeline Co.*, the Commission approved a proposal establishing flexible receipt and delivery points on Transwestern's system.[153]

The Commission concludes that it should modify its current policies with respect to flexible receipt and delivery point policies to provide for more flexibility. First, the Commission will require pipelines to give firm shippers flexible delivery points in their distribution areas in the same manner as it gives firm shippers flexible receipt points in the production areas. Firm shippers will have the right to change firm delivery points

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150. 18 CFR 284.221(h).

151. El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,066 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987).

152. 52 FERC ¶ 61,041 at p. 61,193 (1990).

153. 58 FERC ¶ 61,299 (1992).

and to use other delivery points on an interruptible basis without losing their priority for firm service.[154] The allocation of capacity at receipt and delivery points will be determined in the restructuring proceedings and set out in the pipeline's tariff as required by new Section 284.14(b)(1)(v) of the Commission's regulations. Second, the Commission will expand firm shippers' rights to receipt and delivery points to include the right to receive gas from any person at any place on the system and the right to deliver gas to any person at any place on the system on a firm basis with the flexibility to change firm receipt and delivery points and to use all delivery points on an interruptible basis. Of course, receipt and delivery points must be within the firm transportation capacity to which the shipper is entitled, and for which it pays. So, for example, an LDC in a downstream region of the country could arrange to deliver gas to an LDC or an industrial in an upstream region,[155] but conversely an LDC in an upstream region could not arrange for delivery in a downstream region.

The Commission believes that these policies are necessary to promote maximum efficient usage of the pipeline systems. For example, flexible receipt and delivery points are necessary to the continued development of market centers where pipelines interconnect. In addition, both flexible rights to receipt and delivery points and distribution area delivery point flexibility are necessary to achieve a broad and meaningful firm capacity releasing program. The Commission believes that the new firm capacity releasing program can operate in a nondiscriminatory

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154. This refers to existing capacity at the distribution area delivery points.

155. The issue of industrial customers potentially by-passing an LDC is discussed below in the transition cost section.

manner alongside the pipeline's allocation of its own available capacity on the electronic bulletin board as discussed above. The new capacity releasing program and flexible delivery point policy mean that a shipper will not lose its firm capacity by changing firm delivery points in order to permit another entity to ship gas through the releasing shippers' firm capacity. Any Commission orders that indicate that a shipper would lose its right to firm mainline capacity by changing firm delivery points are overruled.[156]

H. Curtailment

The Commission's current curtailment policy is that the NGPA Title IV system of curtailment priorities for certain end users applies to curtailments that result from a shortage of pipeline gas supplies[157] and not to curtailments that result from a shortage of transportation capacity.[158] As the Commission stated in Order No. 436:

> [G]as being transported normally should not be subject to curtailment by the pipeline at all, because it would be the pipeline's system

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156. *E.g.*, El Paso Natural Gas Co., 35 FERC ¶ 61,440 at p. 62,066 (1986), *reh'g denied*, 38 FERC ¶ 61,008 (1987) and Texas Eastern Transmission Corp. 37 FERC ¶ 61,260 at p. 61,684 (1986).

157. 15 U.S.C. 3391-4 (1988); El Paso Natural Gas Co., 54 FERC ¶ 61,316 at p. 61,954 (1991).

158. *E.g.*, Order No. 436, supra n.2, at p. 31,515; Order No. 436-A, *supra* n.2 at pp. 31,652-53; *Cf.*, Sebring Utilities Com'n v. FERC, 591 F.2d 1003 (5th Cir. 1979), *cert. denied*, 444 U.S. 879 (1979).

> supply, not the shippers' gas, that would be curtailed.[159]

Accordingly, when a pipeline's gas supplies are scarce, the pipeline should curtail its sales customers without affecting its transportation customers.

With respect to capacity-related curtailments, the Commission has routinely authorized pipelines to have transportation curtailment plans which differ from their sales curtailment plans, and has specifically approved transportation curtailment plans which are based on *pro rata* allocations of capacity.[160] The Commission has, however, permitted parties to agree to an end-use specific transportation capacity curtailment plan.[161]

The NOPR proposed to continue the existing policies with respect to supply and capacity curtailment.

The commenters raise two similar points. Some would apply

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159. Order No. 436, *supra* n.2, at p. 31,515; Order No. 436-A, *supra* n.2 at pp. 31,652-53.

160. *See* Texas Eastern Transmission Corp., 37 FERC ¶ 61,260 (1986); Southern Natural Gas Co., 41 FERC ¶ 61,218 (1987).

161. Florida Gas Transmission Co., 51 FERC ¶ 61,309 (1990); United Gas Pipe Line Co., 46 FERC ¶ 61,314, *order on reh'g*, 49 FERC ¶ 61,096 (1989). Those cases involved settlements where the parties agreed to the curtailment plan. In United, the Commission did find that the capacity curtailment provision was in compliance with the requirements of Title IV of the NGPA. However, the effect of that order was to approve a specific settlement agreement, and any inference that the NGPA mandates end-use specific curtailment plans is misplaced.

the NGPA Title IV priorities to capacity curtailment.[162] Others argue that Title IV priorities should not apply to supply curtailment in an unbundled environment.[163] Both arguments would result in similar treatment for all gas by either applying the NGPA Title IV priorities in all curtailment circumstances or not applying the priorities in any circumstances. In the alternative, Elizabethtown would require pipeline sales customers to exhaust other sources of gas supply and agree to compensate the LDCs suffering more than pro rata curtailment. The Industrial Group would allow the pipelines' customers to fashion emergency plans in the event of *force majeure* capacity curtailment to prevent LDCs from having to cut-off their customers.

The Commission agrees with the commenters' theory that to put pipeline sales and sales by others on an equal footing requires the equal treatment of all gas for both supply and capacity curtailment purposes. However, as stated in *Transcontinental Gas Pipe Line Corp.*,[164] "[u]ntil Congress changes the [NGPA], the statutory priority [for pipeline sales] must be observed."[165] Thus, Title IV of the NGPA must continue to apply to sales only. Moreover, the Commission does not believe it is appropriate to require high priority customers to exhaust other sources of gas supplies before application of the

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162. *E.g.*, Agricultural Minerals Corporation and the Fertilizer Institute

163. *E.g.*, Elizabethtown Gas Company.

164. 57 FERC ¶ 61,345 (1991).

165. *Id.* at p. 62,117.

NGPA Title IV priorities to pipeline sales.[166] With respect to the comments about compensation among pipeline customers in the event of a supply curtailment under the Title IV priorities,[167] the Commission will not prevent, and indeed encourages, such inter-customer agreements. In addition, it may be possible for sales customers of pipelines to reflect their Title IV priorities in their negotiated pipeline supply charges.

However, with the unbundling of pipeline sales from transportation, the NGPA Title IV priorities will only apply to a narrow category of gas supplies — pipeline sales near the wellhead. After the point of sale, all gas will move through the pipeline as transportation gas and will not be required to be curtailed by the NGPA Title IV categories. Rather, the curtailment of deliveries owing to capacity curtailment must be done on a *pro rata* basis or some other basis developed by the parties in the restructuring proceedings.[168] However, the rules and allocation priorities of transportation capacity curtailment plans must be set forth clearly and specifically in the pipelines' tariffs.

The Commission urges the parties to develop tariff mechanisms that provide flexibility, because at the time a need

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166. *Id.* n.57, where the Commission rejected Elizabethtown's request that gas purchasers seeking NGPA Title IV relief take certain remedial action first.

167. *E.g.*, Elizabethtown Gas Company and the Process Gas Consumers Group, American Iron and Steel Institute, Chemical Manufacturers Association, Georgia Industrial Group, and the Association of Businesses Advocating Tariff Equity (Industrial Groups).

168. See n.160 and 161, *supra*.

for capacity curtailment arises it may not be possible to identify ownership of the gas or to control its flow. Hence, it is expected that gas will continue to flow to those who need it for heating or other important needs without regard to any *pro rata* curtailment plan. Therefore, the participants in the restructuring proceedings should address ways to deal with the emergency shortages due to capacity constraints. For example, a pipeline's transportation customers may be willing to release capacity under the capacity releasing mechanism or to sell gas if need be upon reasonable compensation.[169] In any event, the pipelines must file with the Commission, as part of their tariffs, their supply and capacity (transportation and storage) curtailment plans in sufficient detail to accommodate the interests of all shippers. The Commission retains sufficient authority under this rule to prescribe accounting or allocation procedures if needed in the future.

Whether in connection with capacity curtailment or otherwise, the Commission is concerned about allegations that pipelines have permitted the diversion of a customer's gas (*e.g.*, an industrial) to another customer (an LDC).[170] While some commenters suggested the Commission adopt rules on gas accounting matters,[171] the Commission believes it unwise to mandate particular solutions. However, the Commission will require the parties to the restructuring proceedings to address

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169. For example, see the Industrial Groups' proposal in its response to the Commission's Notice of Technical Conference in Docket No. RM91-11-000.

170. *See* the Staff Summary of December 1989 Curtailment Survey Response, Docket No. TC90-8-000, Nov. 1, 1990.

171. *E.g.*, the IPAA.

the issue of the diverting of gas owned by one shipper to another shipper. The participants should explore the possibility of flow control by the pipeline to prevent customers from taking gas. In addition, participants must address the need for and cost feasibility of accurate and timely measurement equipment so that pipelines know how much gas is in the system, whose gas it is, and who is taking delivery of the gas. Pipelines will be allowed cost recovery for purchasing and installing such equipment in their NGA section 4 rate cases, subject to prudence reviews. As indicated above in connection with capacity curtailment, the participants should also explore the need for authorized diversion where the gas can be diverted in specific circumstances with reasonable compensation.

VIII. RATE DESIGN

A. Introduction

As part of the Commission's actions to improve the competitive structure of the natural gas industry, the Commission will adopt the proposed rule and require a generic change in pipeline transportation rates to eliminate potential competitive distortions in pipeline rate structures. Specifically, the Commission's task is to determine the appropriate level of fixed transportation and storage costs to be recovered through the reservation charge[172] and usage charge in designing pipeline rates.[173] This determination is known as cost classification and

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172. Section 284.8(d) of the Commission's regulations permits pipelines to charge a reservation fee. The Commission will here refer to reservation charge rather than demand charge even when the discussion relates to the firm sales demand charge.

173. The usage charge is also referred to as the commodity charge. (Cont'd)

is one part of the ratemaking process described below.

The Commission engages in five steps in fashioning a pipeline's rates for its jurisdictional customers. The first task is to determine the pipeline's overall cost of service.[174] The second task is to functionalize the pipeline's costs by determining to which of the pipeline's various operations or facilities the costs belong. This step is known as functionalization and mainly turns on the particular characterization of the pipeline's facilities as production area, transmission, or storage facilities. The third task is to categorize the costs assigned to each function as fixed costs (which do not vary with the volume of gas transported) or variable costs, and to classify (*i.e.*, assign) those costs to the reservation and usage charges of the pipeline's rates. This step is known as classification. The fourth task is to apportion the costs classified to the reservation and usage charges among the pipeline's various rate zones and among the pipeline's various classes of jurisdictional services. This step is known as allocation. The fifth task is to design each service's rates for billing purposes by computing unit rates for each service. This step is known as rate design. The entire process is known as ratemaking.

The instant rule will not address functionalization, which is mainly important in determining whether facilities are jurisdictional or nonjurisdictional.[175] The Commission will

(Cont'd)
However, usage is the correct term to use in connection with transportation, rather than sales, rates.

174. The pipeline's cost of service is the total revenues needed to cover the pipeline's operations, including a just and reasonable return on its rate base.

175. *See, e.g.*, Trunkline Gas Co. 58 FERC ¶ 61,240 (1992) and Interstate Natural Gas Pipeline Rate Design, 56 FERC ¶ 61,086 (1991).

continue to functionalize between transportation and gathering based on the modified *Farmland* test.[176] The present focus is on classification as it relates to allocation and to the designing of the actual rates.

B. Background

The Commission uses the cost classification aspect of the ratemaking process to achieve policy goals that are pertinent to current conditions. Because conditions change over time, the Commission's goals change and the weight given to various goals also changes. This balancing of goals is a matter of judgement and is not an exact science.[177]

Frequently, however, the Commission has emphasized one particular goal in its ratemaking. That goal is to design pipeline rates in light of competition. This has involved the shifting of costs from the commodity to the reservation charge to keep pipeline rates competitive. For example, in 1965, the Commission approved rates that put ninety-six percent of a pipeline's fixed costs in its reservation charge to take into account competition from coal.[178] After the curtailment era, in

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176. Farmland Industries, Inc., 23 FERC ¶ 61,063 (1983) and Amerada Hess Corp., *et al.*, 52 FERC ¶ 61,268 (1990).

177. Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945) ("Allocation of costs is not a matter for the slide-rule. It involves judgement on a myriad of facts.")

178. *E.g.*, Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967) (The court affirmed the Commission's deviation from the Seaboard (see *infra*) method by putting 96 percent of fixed costs in the demand charge over the objection of coal associations.).

1983, the Commission first adopted the modified fixed variable (MFV) method in recognition of the annual underutilization of pipeline facilities.[179] MFV also was devised to help pipelines sell gas by moving all fixed costs except for return on equity and related taxes to the reservation charge.[180] In almost all cases, MFV reduced the pipeline's fixed costs included in its commodity charge compared to the fixed costs included in the commodity charge under the previously used *Seaboard*[181] or *United* methods.[182] MFV, therefore, was adopted in pursuit of the goal of competition by lowering pipeline sales commodity charges to enable gas to compete effectively with alternative fuels such as oil.

The Commission again emphasized the need for competitive rates when it adopted Order No. 436.[183] Section 284.7(c) of the

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179. Natural Gas Pipeline Company of America, 25 FERC ¶ 61,176 (1983), *order on reh'g*, 26 FERC ¶ 61,203 (1984), *aff'd in relevant part*, Northern Indiana Public Service Co. v. FERC, 782 F.2d 730 (7th Cir. 1986).

180. Future references to fixed costs are to fixed transmission and storage costs. Storage will be unbundled from transportation and separately charged. However, some storage may be retained by the pipeline for its balancing and system management operations associated with transportation and for its no-notice transportation service.

181. Atlantic Seaboard Corp., 11 FPC 43 (1952) (Fifty percent of fixed costs recovered in the commodity charge).

182. United Gas Pipe Line Co., 50 FPC 1348 (1973), *aff'd sub nom.*, Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176 (D.C. Cir. 1975) (Seventy-five percent of fixed costs recovered in the commodity charge).

183. See n.2, *supra*.

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Commission's regulations, promulgated by Order No. 436, sets forth the Commission's rate objectives in designing maximum rates for both peak and offpeak periods. In addition to rationing capacity during peak periods,[184] Section 284.7 states that "rates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput."[185] In addition, Section 284.7(d)(5) authorized pipelines to discount their transportation rates below the maximum rate in order to adjust the price to meet competition from competitive fuels and from other pipelines.[186]

The Rate Design Policy Statement, while emphasizing the possible need to ration capacity, also recognized the importance of maximizing throughput in its discussions of discounted rates and rates for interruptible transportation service. In *Panhandle Eastern Pipe Line Co.*, Opinion No. 369,[187] the Commission refined its approach to the rationing capacity and maximizing throughput goals by retaining MFV for cost allocation purposes because there was no need to ration capacity on Panhandle's system,[188] but adopted the straight fixed variable (SFV) for rate design (billing) purposes because of the need to put all fixed costs in the demand charge to maximize Panhandle's throughput.[189]

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184. "Rates for service during peak periods should ration capacity." 18 CFR 284.7(c)(1).

185. 18 CFR 284.7(c)(2).

186. Order No. 436, *supra* n.2, at pp. 31,543-545.

187. 57 FERC ¶ 61,264 (1991).

188. *Id.* at p. 61,843.

189. *Id.* at p. 61,827-30.

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C. Discussion

The Commission has discussed above in detail the evolution of the natural gas industry from a regulated, interstate, sales for resale industry with LDCs purchasing gas at the city gate to a decontrolled gas market with gas sold in the production area and transported to the city-gate under Part 284 open access transportation.[190] The Commission is here adopting regulations to ensure that all gas supplies are moved to market on even terms. The Commission is adopting these regulations in order to promote competition among gas sellers (including the pipelines as merchants) in a now national gas market to ensure consumers access to adequate supplies of clean and abundant gas at reasonable prices. The Commission's task is to analyze cost classification, in light of the goals discussed in this order. The appropriate cost classification method used to allocate costs and design rates should in no way inhibit the creation of a national gas market of efficient gas merchants as envisioned by Congress in enacting the Decontrol Act. Ratemaking, like transportation terms and conditions, should comport with the goal that all gas should be shipped on even terms.[191]

The first question is whether the pipelines' currently effective cost classification methods will inhibit the goal of the development of a competitive, national gas market and,

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190. In 1990, transportation amounted to 79 percent of the total gas delivered for market by pipelines. INGAA November 1991 paper, *supra*, Table A-1.

191. At times, the issue has been framed in the context of competition between Canadian and domestic gas. *See* Opinion No. 357, Iroquois Gas Transmission System, L.P., *et al.*, 53 FERC ¶ 61,194 at pp. 61,712 n.91 (1990) and Tennessee Gas Pipeline Co., 51 FERC ¶ 61,113 (1990) (NIPPS II).

therefore, do not comport with the goals set forth in this order or with Congress' goals in enacting the Decontrol Act. In particular, the inquiry is whether the pipelines' current methods distort the gas purchaser's decision because the transportation usage charges vary in the amount of fixed costs included in each pipeline's transportation usage charge. Because the currently effective cost classification method used by most pipelines is MFV, this order will discuss the instant issue with reference to MFV. However, the following discussion and conclusion about MFV applies equally to other methods that recover fixed costs in the usage charge.

Pipelines have differing amounts of fixed costs in their usage charges because those fixed costs (return on equity and related income taxes) are determined by reference to revenue requirement criteria that differ on each pipeline. The portion of the revenue requirement for the return on equity depends on the size of a pipeline's rate base, the pipeline's ratio of equity to total capital, and the allowed rate of return on equity. Because pipelines have rate bases that vary according to their original costs and how much they have been depreciated, and because pipelines have different capital structures and allowed rates of return on equity, the pipelines have different amounts of fixed costs in their usage charges under MFV.[192] Moreover, MFV could bias the debt-equity ratio because pipelines can increase their debt component to lower their usage charges for competitive reasons.

This situation of differing levels of fixed costs in pipeline usage charges can hinder competition between gas sellers at the wellhead because competition is not based on the seller's costs

192. The more equity a pipeline has in its capital structure, the more return and related taxes will be in the usage charge.

and therefore on their ability to compete directly with each other. Rather, competition for sales customers is influenced by the fixed costs in the pipeline transportation usage charges. For example, producers in different fields that compete for market share via different pipelines will often have their competitive positions in that market affected by the amount of fixed costs in the pipelines' respective transportation usage charges and not by the producers' own costs and efficiencies in producing gas. The MFV cost classification method results in the shipment of gas on uneven, rather than on even, terms and will inhibit the development of a national market which "will yield lower prices and more abundant supplies" by "over time forc[ing] the evolution of a set of lowest-cost producers" as envisioned by Congress in decontrolling the price of gas at the wellhead and in the field.[193] Accordingly, unless the Commission permits otherwise, as described below, the Commission concludes that MFV is not in the public interest, unreasonably hinders competition among gas sellers, and is unjust and unreasonable under NGA Section 5.

The Commission here is addressing cost classification for both cost allocation and rate design (billing) purposes. This means that the Rate Design Policy Statement no longer will be applicable to apportioning costs to the reservation and usage charges. However, the Rate Design Policy Statement still will be applicable to other matters, such as the determination of rates for interruptible transportation, the discounting of rates, and the requirement that rates "reasonably reflect any material variation in the cost of providing the service due to . . . [t]the distance over which the transportation is provided."[194]

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193. H.R. Rep. No. 29, *supra*, at p. 7.

194. 18 CFR 284.7(d)(3).

Specifically, the Commission is amending Section 284.8(d) of the regulations to require pipelines to recover their transportation costs under the straight fixed variable (SFV) method of assigning all fixed costs related to transportation to the reservation charge. The Commission, however, will not rigidly preclude the pipeline, its customers, and interested state commissions, producers, marketers, brokers, end-users, and others from agreeing to an alternative method that deviates from SFV and may be appropriate to that particular pipeline system. If the parties affected by a pipeline's rate design agree to a different method, the Commission will consider giving effect to the parties' agreement. However, to the extent a pipeline's rates deviate from SFV, the Commission will carefully consider the arguments of those parties[195] proposing the deviation as well as the parties opposing the deviation. Thus, while a single party cannot preclude the Commission from considering a deviation from SFV, any party (or parties) advocating something other than SFV carries a heavy burden of persuasion. The language in section 284.8(d) of the regulatory text implements this approach and ensures that the Commission will ultimately resolve this issue.

The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equality principle. Under SFV, all gas merchants would be able to compete in a national market without regard to fixed transportation costs included in the usage charge.[196] This

195. Parties include, among others, pipelines, producers, marketers, brokers, LDCs, state commissions and agencies, and end-users, such as industrials and gas-fired electric generators.

196. Only a small amount of variable costs (such as fuel) would be in

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approach is as essential to the shipment of gas on even terms as is equality in the quality of service with respect to gas transportation. SFV would, therefore, maximize the benefits of wellhead decontrol by increasing the nationwide competition among gas merchants (including pipelines). This should result in head-to-head, gas-on-gas competition where the firm transportation rate structure is not a potentially distorting factor in the competition among merchants for gas purchasers at the wellhead and in the field. This merchant-to-merchant competition should help to achieve Congress' intent in passing the Decontrol Act to "over time force the evolution of a set of lowest-cost producers."[197] This "will yield lower prices and more abundant supplies" and benefit all consumers of gas.[198]

Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant natural gas over alternate fuels such as foreign oil.[199] SFV is the best method for doing that. As

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the firm transportation usage charge. Interruptible transportation rates will continue to be determined on a case-by-case basis under the Rate Design Policy Statement. With unbundling, the role of interruptible transportation should be diminished.

197. H.R. Rep. No. 29, *supra*, at p. 7.

198. *Id.*

199. S.R. Rep. No. 39, *supra*, at p. 2 and H.R. Rep. No. 29, *supra*, at p. 2.

discussed above, using cost classification to design rates to influence the consumption of gas is a traditional regulatory technique of the Commission. For example, the Commission has removed costs from the commodity charge to enable pipelines to meet competition for fuel switching customers from coal.[200] And, indeed, the Commission adopted MFV in the context of competition from oil. The Commission finds it appropriate to use that technique again in the current circumstances.

D. Comments on the NOPR's Proposal

The NOPR proposed to adopt SFV for cost allocation and rate design. A few commenters support the NOPR's proposal to mandate the use of SFV generically.[201] More commenters support SFV as a method to be implemented on a case-by-case basis.[202] A number of LDCs and state commissions oppose SFV.[203] Their objections fall into two categories. They first

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200. See, *e.g.*, the discussion of gas versus coal competition in Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967).

201. *E.g.*, Independent Petroleum Association of Mountain States, Colorado Oil and Gas Association, Independent Petroleum Association of New Mexico and Wyoming Independent Producers Association, Panhandle Eastern Pipeline Group (in most instances), and IPAA (presumption).

202. *E.g.*, Natural Gas Supply Association/Indicated Producers and INGAA. The Department of Energy generally endorses the use of straight fixed variable but asks the Commission to "make it clear other rate designs will be approved on a case-by-case basis." Initial Comments at 3.

203. *E.g.*, Distributors Advocating Regulatory Reform, Public Service Commission of the State of New York, Brooklyn Union Gas Company, Baltimore Gas and Electric Company, and Wisconsin Public Service Commission.

argue that the Commission has not established that MFV is anticompetitive. In that vein, they argue that gas purchasers base their gas purchasing decisions on total costs and not only on incremental costs as assumed by the Commission. They also argue that SFV conflicts with other rate design goals. In that vein, they question the impact of SFV on pipeline incentives to enhance service reliability, maintain or maximize throughput, for example, in pipeline-to-pipeline competition, and control costs and the construction of facilities. In addition, they express concerns about the shifting of costs to low load factor customers and about the possibility that LDCs will be forced to reduce their contract demand levels and their ability to reliably serve their customers.

E. Discussion of Comments

1. Mitigation of Cost Shifts

As stated above, commenters express concerns about the shifting of costs to low load factor customers and about the possibility that LDCs will be forced to reduce their contract demand levels and their ability to reliably serve their customers. The Rate Design Policy Statement recognized the possible need for pragmatic adjustments in the event a particular method leads to undesirable or inequitable results, and required administrative law judges to "consider and articulate the impacts (benefits and detriments) of the various rate design proposals on the participants, on the various segments of the industry, and on classes of customers."[204]

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204. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 at p. 62,054 (1989).

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The Commission recognizes that the use of SFV, without any adjustments, could result in cost shifting among customer classes. The Commission will require each pipeline to file the information necessary to determine whether mitigation measures are necessary. Accordingly, each pipeline must include in the compliance filing required by this rule a comparison of the revenue responsibility of each customer class, as they have been historically defined, for the unbundled services under (1) the pipeline's last approved cost classification method for cost allocation and rate design and (2) the SFV cost classification method for cost allocation and rate design. If the comparison shows that adopting SFV for cost allocation and rate design will result in a 10 percent or greater increase in revenue responsibility for any customer class, the Commission will require the pipeline to develop and implement a plan to phase-in any such rate increase over no more than four years. The Commission is establishing a bright-line test here for deciding whether cost shifts caused by the switch to SFV must be mitigated. This test applies only to cost shifts due to the change to SFV. Rate changes attributable to other aspects of this rule are not to be considered in determining whether a cost shift is 10 percent or greater.

The pipeline must include in the compliance filing a plan for phasing-in the cost shifts due to SFV over no more than a four year period. This is a one-time mechanism that will automatically terminate no later than four years after the Commission accepts the pipeline's filing in compliance with the final rule. Potential phase-in methods could include use of a one-part volumetric rate or seasonal contract entitlement levels for small customers, creation of new customer classes based on load factor ranges, or creation of new customer classes on that or another basis in order to continue the use of MFV for cost allocation and SFV for billing.

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Unless the Commission allows a pipeline to use a method other than SFV, in requiring this phase-in, the Commission does not intend to delay implementation of SFV. In addition, SFV must be used for billing purposes even if a method of mitigating cost shifts is used, unless the Commission permits a pipeline to use a method other than SFV as its approved method of cost classification. The Commission's objective is to provide a reasonable period in which a pipeline's customers can adjust to the new cost classification methodology. The Commission will not mandate any specific type of phase-in plan or requirement at this time. However, as stated, the phase-in plan *must* be included in the compliance filing required under new section 284.14. Finally, the Commission will not accept any mitigation proposal that hinders mandatory unbundling and the Commission's movement towards the use of SFV.

Some commenters argue that the Commission should permit firm transportation customers to reduce their contract entitlements to service in connection with the adoption of SFV.[205] The Commission concludes that it is appropriate to allow reductions of contract entitlements to firm transportation service where another person is willing to take the capacity. The Commission has provided firm shippers with the ability to shed unwanted capacity to other persons desiring firm capacity via the capacity adjustment procedure of the restructuring proceedings discussed *infra*, and the capacity releasing mechanism, discussed, *supra*. The Commission concludes these mechanisms are adequate especially in light of the phasing-in of increases of 10 percent or greater in the revenue responsibility of an historic customer class as discussed above.

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205. *E.g.*, the Industrial Groups.

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2. Pipeline Incentives

The Commission has stated in the past that pipelines need an incentive to keep their costs low through an exposure to risk through the assignment of fixed costs to the usage charge.[206] Under SFV, no fixed costs are assigned to the usage charge. Many commenters focused on this point.

The Commission intends to continue to ensure that construction projects are prudent and, of course, pipeline customers may challenge the prudence of pipeline expenditures in rate proceedings. In addition, with respect to transportation throughput, the pipelines will now have much less influence on the use of their systems because they are transporting gas to, rather than selling gas at, the city gate. Transportation volumes will mainly be a function of the needs of gas purchasers and the prices offered by gas sellers in the production areas. The Commission believes that incentive ratemaking may be a better vehicle than exposure to risk for enhancing pipeline efficiency with respect to transportation costs. The Commission is awaiting comments on the proposed policy statement on incentive ratemaking.[207] The proposed policy statement also specifically requested comments on how that policy proposal relates to the rate design methodology proposed in the NOPR. The Commission also recognized that there is a relationship between the proposed policy statement and any restructuring proceedings

206. *See, e.g.*, Texas Eastern Transmission Corp., 37 FERC ¶ 61,260 at p. 61,700-01 (1986).

207. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, Docket No. PL92-1-000, issued March 13, 1992, 58 FERC 61,287 (1992). Comments are due on or before April 27, 1992.

necessitated as a result of this final rule and stated that, after a review of the comments filed in Docket No. PL92-1-000, the Commission will issue guidance in that docket on how a final policy statement affects these restructuring proceedings. The Commission expects to consider the final policy statement in the near future to accomplish this objective in a timely manner.

Last, the Commission received many helpful comments on the impact of SFV on the analysis of pipeline risk in determining rate of return on equity.[208] However, the Commission will not address this issue here because pipeline risk is a matter for pipeline-specific analysis in light of all risks. SFV is but one aspect of risk analysis. This issue is more appropriately addressed in rate proceedings where the Commission examines all other factors affecting risk and establishes the pipeline's allowed rate of return on equity.

3. Gas Purchase Decisions

Niagara Mohawk Power Corporation argues that the Commission's competitive analysis is incorrect because gas purchasers choose between long-term gas suppliers by estimating the "*total* delivered cost of the gas (including both the supply cost and the transportation demand and commodity charges)".[209] Niagara Mohawk asserts that the gas purchasers will not change gas suppliers based on mere changes in the commodity component (gas cost and transportation commodity charge). The Commission recognizes that gas purchasers enter

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208. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 56 FERC ¶ 61,037 at p. 61,136 (1991) (The Commission imposed a 25 basis point reduction in the approved rate of return on equity to reflect the possibility of lower risk.).

209. Initial comments at 32 (emphasis is original).

into long-term and short-term contracts based on the expected total delivered cost. However, even so, this does not invalidate the Commission's analysis. First, the active and viable spot market indicates that a significant amount of gas is purchased on a short-term as well as on a long-term basis.[210] Many purchasers are now developing portfolios of gas supply contracts that are both short- and long-term.[211] Those gas purchasers must make their decisions by comparing the expected incremental cost of the deals available. Spot market sales should continue to play a role in the gas sales market with the implementation of unbundled transportation because a significant amount of gas now moving on an interruptible basis to gas buyers should move on a firm basis, improving the quality and lowering uncertainty associated with gas transactions. This may even increase the use of spot gas to satisfy both base load and peak needs, since the marginal delivered cost to the buyer should be lower because of the combination of unbundled firm transportation and the use of SFV. Hence, the Commission's analysis is directly applicable to a significant and important segment (spot sales) of the natural gas market.

Second, gas purchasers will not be prevented from continuing an expected total cost analysis in entering into new long-term contracts. And it may be easier to compare potential gas sources because no fixed costs under SFV will vary by the estimated purchase volumes. Removing this uncertainty should promote more efficient gas contracting decisions.

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210. See n.41, *supra*. This is further attested to by the fact that in 1990 pipeline sales gas amounted to 21 percent of pipeline carriage for market and that interruptible transportation amounted to 51 percent of carriage for market. INGAA November 1991 paper, *supra*, Tables A-1 and A-6.

211. *See* Initial Comments of the American Gas Association at Appendix A.

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IX. PIPELINE SALES

A. Blanket Sales Certificates

The Commission is requiring all pipelines that provide open access transportation to offer their sales services on an unbundled basis. To this end, the Commission is issuing to pipelines holding a blanket transportation certificate under Subpart G of Part 284 of the Commission's regulations, or performing transportation under Subpart B, a blanket certificate authorizing firm and interruptible sales for resale. All firm and interruptible sales services will be provided as unbundled services under the blanket sales certificate. This form of regulation will enable the pipelines to compete directly with other gas sellers on the same terms at prices determined in a competitive market. The unbundled sales services will be afforded pregranted abandonment (see *infra*).

In addition, existing firm sales entitlements of the pipeline's customers will be converted to unbundled firm transportation rights. The pipeline's existing bundled, city-gate service obligation will be supplanted as of the effective date of the tariff sheets to be filed to comply with this rule. The firm sales customers will have the right to reduce their unbundled firm sales entitlements in whole or in part effective on the effective date of the blanket sales certificate. This will enable the pipeline's firm sales customers to freely negotiate the quantity and price of supplies purchased from the pipeline or other gas suppliers, and thereby take advantage of potential opportunities for long-term sales contracts in the competitive market.

During the restructuring proceedings, the firm sales customers may elect whether to continue their contractual relationship with the pipeline under the new blanket sales

certificate. In making this election the customer can negotiate with the pipeline for the price it will pay for the gas. If the pipeline's price is higher than the price the customer is willing to pay, the customer can elect not to contract with the pipeline and can purchase supplies from another gas seller and the pipeline's sales service obligation ceases. If a customer elects to continue its firm sales service in whole or in part from the pipeline, then the pipeline's service obligation correspondingly continues until the contract terminates, either at the end of its term or by mutual agreement. If the customer elects to terminate its existing sales entitlement in whole or in part, the pipeline's corresponding obligation to serve that customer ceases. If the pipeline and a customer enter into a new contractual arrangement during the restructuring proceeding, that contract will define their relationship under the new blanket sales certificate which becomes effective at the culmination of the restructuring period when the Commission accepts tariff sheets putting the pipeline in full compliance with this rule. Under the new blanket sales certificate, the pipeline's sales obligation will be coextensive with its contractual obligations. When its unbundled sales contract expires, the pipeline is authorized to abandon its sales service.

A transportation only pipeline will not be required to offer and sell gas under the blanket sales certificate. Of course, such a pipeline may elect to offer gas in the future under the blanket sales certificate by filing appropriate tariff sheets.

In addition, the Commission is including standards of conduct and reporting requirements as part of the regulations governing blanket sales certificates for pipeline sales (see *infra*). The tariff sheets implementing the blanket sales certificate must be filed under Section 284.14 of the regulations when the pipeline makes its compliance filing in the restructuring

proceeding. Therefore, the pipeline may not implement sales service under the new blanket sales certificate until the Commission accepts those tariff sheets. The Commission does not intend to accept those tariff sheets until the pipeline is in full compliance with this rule.

To conclude, the Commission believes that the blanket sales certificates will be in the present or future public convenience and necessity because they will permit pipelines to make unbundled sales in a competitive production area market in furtherance of Congress' aims in enacting the Decontrol Act.

B. Pricing

The Commission has concluded above that pipelines that continue to sell gas must offer firm sales services that are unbundled from their transportation services. Hence, pipelines will be offering sales services separated from distinct transportation services. These pipeline sales services will be competing directly with unregulated sales by other sellers.

The NOPR proposed that pipelines would be allowed to adopt a market-based sales pricing mechanism for their unbundled firm sales services.[212] The NOPR's proposal was based on the Commission's intention to conclude that any pipeline sale markets are sufficiently competitive to prevent all pipelines from exercising significant market power.[213] The

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212. A market-based pricing mechanism could include, among others, two-part gas inventory charges and as-billed recovery of producer demand charges.

213. The Commission previously concluded that it has the legal authority to approve market-based, unbundled, sales rates upon such a finding. (Cont'd)

Commission's conclusion was grounded on two points. First, the Commission proposed to establish comparable transportation service by amending Part 284. Second, the Commission proposed to conclude that adequate divertible gas supplies exist in all pipeline sales markets.[214] The Commission is adopting a rule that will allow pipelines to adopt a market-based pricing mechanism upon full compliance with the final rule. Some commenters argued that there may be areas where market-based rates are inappropriate. A contesting party in a particular restructuring proceeding can seek to prove that the particular pipeline's sales market is not sufficiently competitive. If that showing can be made, the Commission will decide the appropriate regulatory method to use in lieu of that adopted by this rule.

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Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991); Transwestern Pipeline Co., 53 FERC ¶ 61,298, at pp. 62,114-15 (1990); Transcontinental Gas Pipe Line Corp., 48 FERC ¶ 61,199, at p. 61,753 (1989); Transwestern Pipeline Co., 43 FERC ¶ 61,240, at p. 61,650-52 (1988), *reh'g granted in part*, 44 FERC ¶ 61,164 (1988), *remanded on other grounds*, Transwestern Pipeline Co. v. FERC, 897 F.2d 570 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 373 (1990). Such market-based rates are consistent with the Commission's obligation to determine just and reasonable rates under the NGA and are consistent with the Decontrol Act. *See* Transwestern Pipeline Co., 53 FERC ¶ 61,298 at pp. 62,114-15 (1990).

214. The Commission has found that a pipeline's sales are made in a sufficiently competitive market when the pipeline provides comparable transportation service with respect to all gas supplies from whomever purchased and when adequate divertible gas supplies exist. *E.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991); El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

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The Commission's competition conclusion rests on two points. First, the Commission will not approve a restructuring plan for any pipeline unless the Commission concludes that the pipeline will provide transportation services for all gas supplies in compliance with the equality principle adopted and defined by this rule. Second, as discussed below, the Commission is concluding that adequate divertible gas supplies exist in all pipeline markets.

The Commission's conclusion of adequate divertible gas supplies is grounded on Congress' passage of the Decontrol Act. As the Commission has stated:

> That act reflects Congress's finding that the natural gas sales market is competitive. . . . The sale of pipeline gas which is . . . unbundled from any transportation service is now part of that same natural gas market which Congress deregulated, and [the pipeline] is . . . competing directly against the producers and marketers whose gas sales Congress deregulated.[215]

Congress, therefore, has determined that gas sales at the wellhead, or in the field, are sufficiently competitive to justify decontrol of all first sales of gas supplies.[216]

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215. Transwestern Pipeline Co., 53 FERC ¶ 61,298 at p. 62,115 (1990).

216. S. Rep. No. 39, *supra*, at p. 3 ("[P]artial wellhead decontrol under the NGPA has helped to create an environment in which competition, not public utility-type regulation, is the dominant force in determining prices and supplies in the natural gas sales markets[.]").

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Congress did not decontrol or deregulate gas pipelines or gas pipeline sales that are not "first sales."[217] However, at the time Congress acted, what existed was the traditional or classic bundled sales environment for pipeline sales, and not the unbundled sales environment instituted by this rule. The Commission believes that the Congressional finding of a competitive wellhead or field market applies to all sellers in that market, and that it is reasonable to infer that Congress believed that the production area market for natural gas is competitive on a national level without regard to the status of a particular gas merchant as first seller or non-first seller.

In addition, the Commission now finds that, except as discussed below, the issue of whether sufficient divertible gas supplies exist should not be part of its analysis to determine whether a pipeline possesses market power over sales. Throughout the country, there is a significant amount of uncommitted supplies available at competitive prices. In many areas, uncommitted supplies exceed the largest amount of gas controlled by any pipeline connected to the areas. Indeed, the Commission's experience in approving gas inventory charges in the past few years demonstrates that uncommitted gas supplies are available throughout North America.[218] This means that (with the existence of firm transportation under this rule) sellers of uncommitted supplies could replace pipeline sales, and that it will not be profitable for a pipeline to attempt to exercise market power over the sale of natural gas.

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217. See discussion of the Decontrol Act, *supra*.

218. *See, e.g.*, Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991), and El Paso Natural Gas Co., 54 FERC ¶ 61,316 (1991), *order on reh'g*, 56 FERC ¶ 61,290 (1991).

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The Commission concludes that, after unbundling, sellers of short-term or long-term firm gas supplies (whether they be pipelines or other sellers) will not have market power over the sale of natural gas. To repeat, there is no doubt, as Congress expressly found and confirmed, that a competitive market exists for gas at the wellhead and in the field.

The Commission is, of course, aware of the possibility noted by several commenters[219] that particular markets may not be sufficiently competitive to support a finding that a particular pipeline lacks significant market power. Therefore, the Commission will permit any party in the restructuring proceeding to prove that adequate divertible supplies do not exist with respect to a particular pipeline. The Commission will consider these arguments in each restructuring proceeding and will examine any contesting party's claim that adequate divertible supplies do not exist. In addition, any party may raise the issue of adequate divertible supplies in proceedings subsequent to the restructuring proceedings.[220]

It is important to note that only Congress can "deregulate." Therefore, the Commission is instituting light-handed regulation, relying upon market forces at the wellhead or in the field to constrain unbundled pipeline sale for resale gas prices within the NGA's "just and reasonable" standard. The Commission will be regulating the pipeline sales in the same manner as it has done for sales for resale by marketers. Moreover, the Commission's conclusion is premised on the implementation in

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219. *E.g.*, New England Distributors, Marathon Oil Company, and Associated Natural Gas Company.

220. El Paso Natural Gas Co., 56 FERC ¶ 61,290 at p. 62,174 (1991) ("[P]arties may file a complaint with the Commission to present evidence of any change in market conditions which may give market power to El Paso.").

the restructuring proceeding of equally good quality firm transportation service for all gas supplies regardless of the seller's identity. Last, the Commission concludes that market-based pricing for unbundled pipeline sales is necessary to permit pipelines to compete for gas sales with their competitors on an equal basis with respect to pricing gas as a commodity, as well as in the transportation of gas on even terms and conditions. However, the Commission reiterates, the pipeline's authority to make market-based sales under the blanket sales certificates granted here will not be effective until the Commission accepts its filing in full compliance with the final restructuring rule.

The Commission rejects commenters'[221] argument that the Commission's light-handed regulation of unbundled pipeline sales does not conform to *Farmers Union Central Exchange, Inc. v. FERC.*[222] In that case, the court determined that a lightened regulatory hand is permissible so long as the regulatory scheme acts as a monitor to see if rates are within the "zone of reasonableness."[223] In this order, the Commission has determined that pipeline prices will be limited by a just and reasonable ceiling which is set by a competitive national gas market.[224] In

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221. *E.g.*, Gas Company of New Mexico and Northern Illinois Gas Company, Peoples Gas Light & Coke Company and North Shore Gas Company.

222. 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 1034 (1984).

223. *See* El Paso Natural Gas Co, 56 FERC ¶ 61,290 at p. 62,174 (1991).

224. *See also* Importance of Market Centers, *supra*, at pp. 11-14 (The staff concluded that each of seven production-area market centers has significant uncommitted supplies and that most, if not all, of those supplies would be expected to be economically divertible to customers of interstate pipelines.).

addition, equal transportation must be provided on all pipelines. Hence, pipelines will have no significant market power as sellers. However, in the event parties prove that adequate divertible supplies do not exist with respect to a particular pipeline, the Commission will engage in more active regulation of that pipeline's sales. The Commission believes that the regulatory scheme under this rule will act as a monitor to ensure that rates are within a "zone of reasonableness."

C. Blanket Interruptible Sales Service

The NOPR proposed that there be no restrictions on pipeline unbundled interruptible sales services under the proposed blanket sales certificate. The rule adopted here requires the pipeline to offer firm and interruptible sales service only on an unbundled basis. In addition, the Commission has concluded that unbundled pipelines do not possess significant market power over sales. In that context, the Commission concludes that there should be no limitations or restrictions on pipeline unbundled interruptible sales services (other than standards of conduct, *see infra*.) The unbundling of pipeline sales services will enable producers, marketers, and pipelines to compete for long-term sales on the same unbundled basis. The Commission finds no reason why pipelines should be prohibited from competing on an even basis with producers or marketers for unbundled interruptible sales which are, in effect, short-term (spot) sales.

As with firm sales, the Commission will permit blanket interruptible sales only on an unbundled basis. As stated above, the interruptible sale of gas on an unbundled basis is necessary as a "barrier to undue discrimination in the offer of sale discounts."[225] This moots the interruptible sales service issues

225. El Paso Natural Gas Co., 50 FERC ¶ 61,363 at p. 62,094 (1990). (Cont'd)

considered during the May 2, 1990 Technical Conference in *Arkla Energy Resources, Inc., et al.*[226] Any blanket certificates for interruptible sales on a bundled or unbundled basis will be merged into or subsumed within the pipelines' blanket sales certificates.

D. Standards of Conduct

Order No. 497[227] adopted standards of conduct and reporting requirements for interstate pipelines with marketing affiliates.[228] In brief, the pipeline is prohibited from preferring its marketing affiliate over unaffiliated shippers with respect to

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(Cont'd)

See also Arkla Energy Resources, Inc., 50 FERC ¶ 61,366 at p. 62,103 (1990) ("In *El Paso*, . . . the Commission precludes pipeline ISS merchant service from having an undue advantage over pipeline transportation service by means of the movement of the point at which title to ISS gas transfers [to mainline receipt points].").

226. 50 FERC ¶ 61,366 (1990). This proceeding will be terminated.

227. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec. 22, 1989), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 8, 1992), 58 FERC ¶ 61,139 (1992).

228. 18 CFR Parts 161 and 250. *See also* Algonquin Gas Transmission Co., *et al.*, 55 FERC ¶ 61,261 (1991) with respect to pipeline compliance with the reporting requirements of § 250.16 of the Commission's regulations.

transportation matters, access to information, and transportation discounts.[229] In addition, pipelines are required to establish and file with the Commission procedures to enable shippers and the Commission to determine how the pipeline is complying with the standards of conduct.

The NOPR proposed to continue Order No. 497's standards of conduct and reporting requirements for interstate pipelines with marketing affiliates and to apply those standards and requirements to the pipeline when it provides unbundled sales services.

The Commission is continuing Order No. 497's standards of conduct and reporting requirements for interstate pipelines with marketing affiliates even though the pipelines will be making sales on an unbundled basis with transportation separately provided.[230] This is because there is no change in the competitive relationship between marketing affiliates and other shippers, and the need to protect nonaffiliated customers from preferences that could be given to affiliated shippers.

The Commission also concludes that Order No. 497's standards of conduct and reporting requirements should apply to the pipeline when it provides unbundled gas sales services. The pipeline as a merchant would be the functional equivalent of a marketing affiliate. Therefore, nonpipeline suppliers and other customers need appropriate protection from undue preferences that could be given to the pipeline as merchant just

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229. 18 CFR 161.3.

230. Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992).

as much as protection is needed from potential preferences that could be given to marketing affiliates. Accordingly, the Commission will include standards of conduct and reporting requirements as part of the regulations with respect to blanket sales certificates for unbundled pipeline sales.

Pipelines offering unbundled blanket sales services will be required to organize their sales and transportation operating employees so that they function to comply with sections 161.3(a), (b), (d), and (l) and to comply with (c), (e), (f), (g), (h), and (i) by considering their sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate. In addition, those pipelines will be required to conduct their business in conformity with the equality requirements of Sections 284.8(b)(2) and 284.9(b)(2) by not giving shippers of gas sold by the pipeline any preference over shippers of gas sold by any other merchant in matters relating to Part 284 transportation. Consistent with General Instruction No. 2 of the Uniform System of Accounts,[231] pipelines must maintain sufficient accounting records to ensure that the cost of providing each unbundled service can be identified and assigned to such service. For any costs in which direct assignment is not possible or practicable, for example general overhead costs, the pipeline may use any reasonable method for allocating such costs among the various services. However, pipelines must clearly identify each type of indirect cost, and provide justification of the indirect cost allocation methods selected.

Moreover, the pipelines would be required to file procedures[232] and to comply with section 250.16 by considering

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231. 18 CFR Part 201, General Instruction No. 2.

232. This requirement would be similar to that of 18 CFR 161.3(j).

their sales operating employees as an operational unit that is the functional equivalent of a marketing affiliate.[233] However, the reporting requirement should not require pipelines to file separate Form 592 reports with the Commission. Where pipelines already file marketing affiliate reports with the Commission they should file just one combined report for transactions involving marketing affiliates and unbundled pipeline sales.[234]

Many pipelines[235] and some other commenters[236] oppose the Commission's application of standards of conduct and reporting requirements to unbundled pipelines. They argue that the requirements are unnecessary because the market will regulate competition and the NGA prohibits undue discrimination, that their competitors are not subject to such requirements so pipelines will be at a competitive disadvantage, and that the requirements will be too burdensome.

The Commission concludes that the standards of conduct and reporting requirements are necessary to ensure that the pipeline does not favor itself as a merchant over other gas suppliers in performing its transportation function. The pipelines

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233. Section 250.16 sets forth reporting requirements.

234. The Commission's Form No. 592 is being modified to accommodate this minor change.

235. *E.g.*, Coastal Companies, Panhandle Eastern Pipeline Group, Tenneco Gas, and Southern Natural Gas Company.

236. *E.g.*, Affiliated Natural Gas Marketers Association, American Gas Association, and Equitable Resources Energy Group.

are not similar to other merchants because the pipelines control the transportation network. This is a sufficient difference to necessitate the requirements adopted here.

Some commenters[237] argued that the requirements should be strengthened. The Commission believes that any change in the requirements should be considered for both pipeline sales and pipeline marketing affiliate sales at the same time. Hence, the commenters' proposals to strengthen the requirements will not be considered here.

Last, the Commission rejects commenters'[238] requests that small pipelines be exempted on a generic basis from the standard of conduct and reporting requirements. Small pipelines have the same potential for favoring their own sales as do larger pipelines. The Commission will, however, as it has in the past, consider individual requests for waiver from the requirements where it finds that the potential for preferences has been otherwise mitigated.[239]

E. Reporting Requirements

The Commission is requiring the pipelines to file annual reports with respect to their sales under the blanket sales

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237. *E.g.*, Producer-Marketer Transportation Group, Appalachian Energy Group, Independent Petroleum Association of Mountain States, and Hadson Gas Systems.

238. *E.g.*, Pacific Interstate Offshore Company and Pacific Offshore Pipeline Company.

239. Northern Border Pipeline Co., *et al.*, 55 FERC ¶ 61,262 (1991).

certificate. Currently, Section 154.1(a) provides that pipelines are not subject to the "reporting requirements of [P]art 154 governing the filing of contracts, service agreements and related information . . . [for] the sale or transportation of natural gas pursuant to [P]art 284." The Commission is making no change in this regulation.[240] However, the Commission is waiving the requirements of Part 154 of its regulations with respect to the filing of the sales prices between the pipeline and each of its sales customers. The Commission believes that the reporting requirement added by this rule satisfies the filing requirements of the NGA when the purchaser is on notice of the rate and the amount of total revenues from each purchaser is eventually filed with the Commission as an average price as required by the reporting requirement.[241] In addition, the Commission believes that this is appropriate here because the pipeline sales rates will be negotiated with the purchasers. This eliminates the need for advance notice of the pipeline's prices because market-based pricing obviates concerns about discrimination among gas purchasers. In addition, this will enable the pipelines to compete on an even basis with their competitors for gas purchasers because those competitors are under no obligation to disclose their prices to the pipeline.[242]

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240. 18 CFR 154.1(a). Final Regulations Clarifying the Filing Obligations for Part 284 Transportation and Sale of Natural Gas, Order No. 516, 54 FR 47758 (Nov. 17, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,864 (1989).

241. City of Piqua v. FERC, 610 F.2d 950 (D.C. Cir. 1979).

242. *See* Transcontinental Gas Pipe Line Co., 55 FERC ¶ 61,446 at p. 62,335-6 (1991).

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X. PIPELINE SERVICE OBLIGATIONS (AFTER RESTRUCTURING PROCEEDINGS)

A. Introduction

In *American Gas Association v. FERC (AGA II)*,[243] the United States Court of Appeals for the D.C. Circuit reviewed the Commission's regulations promulgated in Order Nos. 500-H and 500-I, and remanded to the Commission the portion of the Commission's decision which provided for pregranted abandonment for each transportation arrangement authorized under a blanket certificate, including transportation arrangements arising out of a sales customer's exercising its right to convert a purchase arrangement to transportation. The court held that the Commission has authority in appropriate circumstances to permit pregranted abandonment under blanket certificates.[244] The court recognized that the event that triggers the pregranted abandonment may be contract expiration. However, the court directed the Commission to develop a further explanation of the criteria under which pregranted abandonment would be permitted. The court was unpersuaded by the Commission's argument that pregranted abandonment helps ensure that capacity will not be retained by existing customers if it is not needed by them, noting that the primary determinant of whether a customer will hold onto excess capacity rights is the size of the demand charge and the degree to which it is related to peak-period use.[245] The court stated that the Commission

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243. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (AGA II).

244. *See also*, Associated Gas Distributors v. FERC, 824 F.2d 981, 1015 n.17 (D.C. Cir. 1987) (AGD I), *cert. denied*, 485 U.S. 1006 (1988).

245. AGA II, *supra*, 912 F.2d 1496 at 1517.

had not adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation — protection of gas customers from exercise of monopoly power through refusal of service at the end of the contract.[246]

On remand of *AGA II,* in Order No. 500-J, the Commission stayed the operation of the pregranted abandonment regulation at issue there, 18 CFR 284.221(d). The stay applied where a customer converted firm sales service to firm transportation service after February 13, 1991, and the Commission indicated its intention to address the issue of pregranted abandonment of transportation service in the context of the instant rulemaking.[247]

Requests for rehearing of Order No. 500-J were filed by numerous parties.[248] Generally, on rehearing, the local distribution companies and state commissions argued that the Commission should vacate its pregranted abandonment rule *in toto,* for firm contracts that are one year or more in length, or

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246. *Id.*

247. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 500-J, 56 Fed. Reg. 6962 (Feb. 21, 1991); III FERC Stats. & Regs. ¶ 30,915 (1991).

248. Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, Panhandle Eastern Pipe Line Company and Trunkline Gas Company, Texas Eastern Transmission Corporation, jointly by Northern Natural Gas Company, Florida Gas Transmission Company, and Transwestern Pipeline Company (Enron), the City of Willcox, Arizona and Arizona Electric Power Cooperative, the State of Michigan and the Michigan Public Service Commission, Indicated Parties, United Distribution Companies (UDC), Associated Gas Distributors, National Association of Gas Consumers, Pacific Gas and Electric Company and the Public Utilities Commission of the State of California.

should extend the stay to small customers who have already converted from firm sales to firm transportation services. The pipelines mainly argued that the stay should be rescinded or at least be only temporary.

After the decision in *AGA II*, the Supreme Court analyzed the Commission's authority to pregrant abandonment in *Mobil Exploration and Producing Southeast, Inc. v. United Distribution Companies* (*Mobil*).[249] The Court held that the Commission has authority under Section 7(b) of the Natural Gas Act (NGA) to decide the issue of abandonment of service in advance, even before service has begun, and that the Commission may make such a determination generically, covering an entire class of cases.[250] As the Court explained, Section 7(b) does not compel the Commission to make specific findings with regard to every abandonment where the issues involved are general. For the reasons discussed fully below, the Commission finds that the proposal in the final rule is consistent with the requirements of Section 7(b) as interpreted in these decisions.

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249. 111 S. Ct. 615 (1991).

250. Section 7(b) states:

> No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

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B. Overview of Final Rule

As part of the effort to foster competition in the natural gas industry, the Commission, in the final rule, is allowing the industry greater flexibility to control transactions through negotiated contracts. Consistent with these steps, it is the Commission's view that a pipeline's service obligation also should be determined, in the first instance, by the contract negotiated by the parties. Thus, the regulations to apply after the initial restructuring required by this rule is complete,[251] generally pregrant abandonment of pipeline service obligations upon the termination of the service contracts, with one exception. During the restructuring proceedings, a pipeline is permitted automatic abandonment of the obligation to transport for a firm shipper, if the firm shipper relinquishes its rights to capacity to a competing bidder rather than agreeing to pay a rate, up to the maximum rate, to match the competing bidder's offer. This one-time only abandonment provision during restructuring proceedings is described fully in section XI.A, *infra*.

In section 284.221(d), which applies after the restructuring period, the final rule authorizes pregranted abandonment of interruptible and short-term firm transportation at the expiration of the contract. The rule defines short-term transportation as transportation under a contract with a term of one year or less. In section 284.285, the rule also authorizes pregranted abandonment for unbundled firm and interruptible gas sales service at the expiration of the contract. Thus, under the rule, a pipeline may cease providing service at the expiration of the contract for these services without first obtaining individual abandonment authority from the Commission under Section 7

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251. Regulations governing the procedures to determine the pipeline service obligation during restructuring are discussed in section XI.A., *infra*.

of the NGA. Similarly, for long-term transportation, the rule permits the parties to determine the pipeline's service obligation through contractual provisions such as roll-over or evergreen clauses. This will be discussed more fully below. Because the definition of transportation is being changed by this rule to include storage, the pregranted abandonment provisions will also apply to storage. However, pregranted abandonment will not apply to existing contract storage because existing contract storage was not authorized under Part 284.

The Commission finds that pregranted abandonment is appropriate for short-term and interruptible transportation because the nature of these services is such that the customers selecting those service options do not rely on continued service at the expiration of the contract. Pregranted abandonment for unbundled sales is appropriate because, as discussed more fully below, a pipeline service obligation is no longer necessary to ensure access to gas supply.

The Commission recognizes that long-term firm transportation (over one year) has characteristics different from the services described above, and, accordingly, the final rule places limitations on pregranted abandonment of long-term firm transportation service. These limitations balance the benefits of greater competition with the shippers' need for continuity of service. First, for long-term firm transportation services, a pipeline and its customers may by contract continue the pipeline's service obligations by extending the term of the contract through inclusion of roll-over or evergreen provisions so that customers have the option to renew or extend the contracts.[252]

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252. "Roll-over" and "evergreen" clauses permit the customer at its (Cont'd)

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Even if a contract does not contain an evergreen or roll-over clause, a pipeline may not abandon service to a long-term firm transportation shipper if that customer elects, within a reasonable time, to exercise a right of first refusal by agreeing to match the terms (as to price and length) of another offer to purchase service from the pipeline. Only if the shipper is unwilling to pay up to the maximum rate, and match the duration of the contract of another offer, will the pipeline's service obligation be abandoned at the expiration of the contract. The details of how the right must be exercised must be worked out in the individual restructuring proceedings and specified in the pipelines' tariffs.

This order and the final regulations resolve the issues that were raised in the requests for rehearing of Order No. 500-J, and the requests for rehearing are granted and denied, consistent with this order. This order explains, *infra,* that pregranted abandonment will not apply to conversions that took place during the period that the Order No. 500-J stay was in effect, *i.e.,* from February 13, 1991, to the effective date of the regulations promulgated in this order.

The specifics of the final rule with respect to each type of service, the comments received on the proposed rule, and any changes from the proposed rule are discussed in greater detail below.

(Cont'd)
option to extend the term of the contract. For long-term firm transportation contracts, the pipeline must offer these provisions on a non-discriminatory basis.

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C. Interruptible Transportation and Short-Term Firm Transportation Service

Section 284.221(d), as amended by the final rule, incorporates the proposal in the NOPR and authorizes pregranted abandonment for all interruptible and short-term (less than one year) firm transportation. The nature of these services is such that customers selecting these options do not rely on continued service at the expiration of the contract. Interruptible customers choose to pay lower rates for less secure service. Short-term transportation customers choose the flexibility of short-term service rather than the stability of long-term commitments. In *AGA II*, the court noted that there was no claim that pregranted abandonment was inappropriate for interruptible transportation. Thus, there were virtually no challenges to the legal basis for authorizing pregranted abandonment for these services.

D. Unbundled Sales Service

The final rule in section 284.285 authorizes pregranted abandonment for unbundled firm and interruptible pipeline sales. Pipelines may cease service to customers for firm and interruptible unbundled gas sales upon termination of their contract without any further action by the Commission. Thus, with the blanket sales certificate, and pregranted abandonment of the sales obligation at the expiration of the sales contract, pipelines are placed in a position that is more comparable to unregulated sellers with which the pipelines must compete. The new post restructuring service obligation of a pipeline to sell gas on a unbundled basis will be co-extensive with its contractual obligation.

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While most commenters, including the LDCs, do not object to pregranted abandonment of unbundled sales service, several have challenged the legal basis for this proposal. Laclede Gas Company (Laclede) and several other commenters[253] argue that pregranted abandonment of unbundled sales service violates Section 7(b) of the NGA. The commenters generally recognize that the Commission can authorize abandonment of services on a generic basis, but argue that that authority is circumscribed by the specific requirements of Section 7(b). Laclede argues that Section 7(b) requires, among other things, that the Commission find on the basis of substantial evidence in the record that the present or future public convenience and necessity allows the abandonment. Midwest Energy opposes the proposal unless the pipeline is required to demonstrate that comparable access to essential transportation, production, and storage exists, and that a workably competitive market for firm gas supply has developed in the relevant geographic market. Similarly, Consolidated Edison argues that in order for the Commission to authorize pregranted abandonment of unbundled sales service, it must first find that sufficient divertible gas supplies currently exist; Consolidated Edison maintains that such a finding is premature.

The Commission disagrees with these arguments. The Commission is authorized to pregrant abandonment upon contract expiration or termination upon a finding that the abandonment is permitted by the present or future public convenience or necessity, pursuant to Section 7(b) of the NGA.[254]

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253. *E.g.*, comments of Midwest Gas and Consolidated Edison Company of New York, Inc.

254. AGA II, *supra*; Mobil, *supra*. See discussion, *supra*.

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The Commission here finds that pregranted abandonment of firm and interruptible unbundled gas sales service upon termination or expiration of the sales contract is permitted by the present or future public convenience and necessity because a continuing pipeline service obligation is no longer necessary to ensure LDCs access to gas supply. Moreover, pregranted abandonment will further the goal of placing all natural gas sellers on an even basis.

The Commission has found above that sufficient divertible gas supplies exist nationwide to prevent a pipeline from exercising market power over the supply of gas at the termination of a contract.[255] Thus, individual abandonment proceedings are not needed to protect LDCs from market power over natural gas supplies and assure continued access to supply. With unbundled firm transportation, LDCs will have as many gas supply options as the pipelines. In addition, the final rule requires pipelines that currently make firm city-gate sales to offer a "no-notice" transportation service[256] that, in combination with unbundled sales, can provide reliable deliveries of gas up to the customer's contract demand level during periods of peak demand. Each firm customer will be entitled to continue this transportation service beyond the term of existing long-term contracts, and preclude the pipeline from abandoning such service, by exercising contractual roll-over or evergreen provisions or by exercising a right of first refusal, as described more fully below. Thus, LDCs will be able to secure new supplies of gas in a competitive market, either from the pipeline

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255. Any allegation that this conclusion does not apply to a particular pipeline will be addressed on a case-by-case basis in the restructuring proceedings. See discussion, *supra*.

256. Described *supra* at section VII.D.

or other sellers, without being subject to pipeline market power over such supply, and will be assured of the means of transporting that gas when it is needed.

Moreover, the rule does not limit the current ability of pipelines and their sales customers to negotiate unbundled sales contracts containing "roll-over" and "evergreen" clauses, such that customers have the option of renewing or extending gas supply commitments from the pipeline. Thus, the application of the pregranted abandonment for unbundled sales service would be deferred as to contracts containing such clauses as long as the purchaser continues to renew or extend the contract because the contractual relationship has not terminated.[257] The inclusion of such clauses in agreements for unbundled sales is a matter of contract, to be determined by the negotiations of the parties, and not by Commission rule or policy.

In addition, pregranted abandonment of future unbundled sales service will further the goals of this rule by permitting pipelines to provide sales service on a more competitive basis with other gas suppliers, who have already been relieved of service obligations that extend beyond the terms of their gas supply contracts by virtue of the NGPA, the Decontrol Act, and previously established Commission policies. In 1978, Section 601(a)(1)(A) of the NGPA removed the Commission's NGA jurisdiction over first sales of new gas that was not dedicated to interstate commerce before the NGPA's enactment, and thus obviated the necessity for producers to secure certificates of public convenience and necessity to sell such gas for resale in

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257. Existing contracts with evergreen clauses will also preclude the availability of pregranted abandonment as long as the customer elects to continue receiving sales service under the contract.

interstate commerce, or to secure abandonment authority to discontinue such sales. Subsequent Commission regulations promulgated under Order No. 451 (Ceiling Prices: Old Gas Pricing Structure) and Order No. 490 (Abandonment of Sales and Purchases under Expired, Terminated, or Modified Contracts) provide producers with blanket sales certificates with pregranted abandonment for pre-NGPA gas. Marketers have been granted blanket sales certificates with pregranted abandonment.[258] As of January 1, 1993, all first sales of gas will be removed from the Commission's NGA jurisdiction under the Decontrol Act. With the unbundling of transportation required by this rule, it is now appropriate to allow pipelines to compete with these other sellers on an analogous basis.

E. Long-Term Firm Transportation

Once again, the following discussion pertains to the application of the regulations after the initial restructuring proceedings are completed. Section 284.221(d), as amended by this rule, places limits on pregranted abandonment of long-term firm transportation service.[259] The criteria established for pregranted abandonment for long-term transportation contracts of long-term firm transportation will foster competition and economic efficiency, and streamline the administrative process, while protecting the legitimate needs of many customers for continued service. The parties may choose to defer application of pregranted abandonment by including evergreen or roll-over clauses in their service contracts. Thus, in the first instance, the parties will decide whether their service obligations under the

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258. *E.g.*, TXG Gas Marketing Co., 55 FERC ¶ 61,063 (1991).

259. There are different procedures that apply during the restructuring proceedings that are discussed *infra* at section XI.A.

contract will be subject to pregranted abandonment. If these provisions are not included in the contract, the customer is still assured the right to continued service if it meets competitive bids, as discussed below.

Under the rule, the parties' ability to use an evergreen or roll-over clause to guarantee the firm shipper a continuing discounted rate will depend on the terms of the existing contract. For example, if the existing contract guarantees the shipper the right to extend the term of the contract at a rate that is less than the maximum rate, the terms of the contract will govern. Otherwise, if there is unsatisfied demand for the capacity, the firm shipper must be prepared to pay up to the maximum rate to retain the capacity. If, however, the pipeline has unused capacity, the parties can negotiate a discounted rate.

These limitations on the pregrant of abandonment for long-term transportation reflect the Commission's determination that the current regulation, which provides for unconditional pregranted abandonment,[260] is not appropriate for firm transportation with a duration of more than one year. The key to continuity of service for a customer is the right to transportation capacity, regardless of the source of gas. The final rule provides customers with the ability to ensure the continued availability of transportation capacity. The Commission finds that with these limitations on pregranted abandonment for long-term firm transportation, the rule meets the requirements of the court in *AGA II*.

1. Comments on the NOPR

Several commenters have challenged pregranted abandonment of long-term firm transportation service, alleging

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260. 18 CFR 284.221(d). See discussion, *supra*.

that the process is inconsistent with Section 7(b) of the NGA. Atlanta and Chattanooga argue that permitting abandonment on a generic basis, subject only to an existing customer's right of first refusal is incompatible with Section 7(b) of the NGA as that section has been interpreted by the courts in *Michigan Consolidated Gas Co. v. FPC*[261] and *Transcontinental Gas Pipe Line Corp. v. FPC.*[262] Atlanta and Chattanooga argue that, consistent with these decisions, abandonment may be authorized only after hearing and a finding that the abandonment is permitted by the public convenience and necessity.

However, neither of the cited cases involves the issue of pregranted abandonment and cannot, in light of *AGA II* and *Mobil*, be read to require the Commission to make an individual determination in all abandonment proceedings. To the extent those cases require a comparative analysis of the public interest considerations for the existing service and the new service, that analysis is set forth in this order, *supra*, and is the basis for the Commission's authorization of pregranted abandonment.

Associated Gas Distributors (AGD) and Consolidated Edison state that a regulation establishing criteria necessary for continuation of service would not be inconsistent with Section 7(b), but a regulation that provides a new customer with an opportunity to take capacity away from an existing customer because it offers different terms would undercut the purpose of the statute. The distinction between the Commission's proposed right of first refusal and a "right to continue" service, as proposed by AGD, is semantic, not substantive. In any event, evergreen and roll-over clauses will provide this right to continue service.

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261. 283 F.2d 204 (D.C. Cir. 1960), *cert. denied*, 364 U.S. 913 (1960)

262. 488 F.2d 1325 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974).

2. The Right of First Refusal

a. Rate Requirement

The exercise of the right of first refusal established in the final rule, that will apply after the restructuring proceedings are complete, will be a means of avoiding pregranted abandonment, in the absence of contractual provisions to extend the contract duration. This right of first refusal will enable any long-term firm transportation customer, including formerly bundled city-gate sales customers, to continue receiving that firm service by agreeing to pay up to the maximum rate and matching the length of contract term offered by another customer who wants and values the service. If the pipeline is willing to discount the transportation rate for competitive reasons, the pre-existing customer may retain the capacity by matching the highest rate, up to the maximum, offered by a competing bidder.[263]

Consolidated Edison of New York and Kansas Power & Light asked for clarification on matching competing bids from a downstream customer. The maximum rate that must be matched means the highest rate the pipeline is authorized to charge for the capacity sought. A bidder in a downstream zone may not force an existing customer in an upstream zone to match the higher maximum rate for capacity to the downstream bidder's delivery point. The maximum rate an existing capacity holder must match is the maximum rate the pipeline can charge for

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263. There is also a similar provision that applies during the restructuring proceeding that is discussed, *infra*, at section XI.A. During the restructuring proceedings, the holder of firm capacity has an opportunity to shed unneeded capacity prior to expiration of its contract, if there is a demand for its capacity, thus triggering the automatic abandonment provisions of § 284.14.

delivery to the existing customer's delivery point. The downstream bidder, however, must bid up to the maximum rate for delivery to its delivery point. If each shipper bids the maximum rate for its zone, and the same length for contract duration, then the existing capacity holder retains its capacity.

This procedure allows the rate to play a role in rationing capacity, but caps the rate at a just and reasonable level. The maximum rate contained in the applicable tariff and approved by the Commission will be at a just and reasonable level and not at a level that results in monopoly rents to the pipeline. The pipeline cannot under any circumstances collect a rate that is above a just and reasonable level, but competitive circumstances may result in a lower rate.

The rate regulations for open access transportation require that pipelines establish a maximum rate designed to recover all of the costs (and only such costs) properly allocated to the service to which the rate applies, and a minimum rate based on the average variable costs.[264] The existing customer is entitled to continue long-term transportation service by matching whatever transportation rate (within the maximum and minimum rates) is offered by another party. If there are no competing offers, the existing customer and pipeline establish the rate (within the maximum and minimum) by negotiation. Therefore, an existing holder of capacity is entitled to continue to receive transportation service upon expiration of its long-term contract, but not necessarily at a discount.

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264. 18 CFR 284.7(d)(4) and (5).

b. Contract Term

The second requirement of the right of first refusal upon expiration of a long-term contract is that the existing transportation customer agree to match the longest contract term offered by another customer interested in receiving the service. Thus, if a competing bidder offers to pay the maximum transportation rate for a term of 20 years, the existing customer cannot retain the capacity by agreeing to pay the maximum rate for some shorter term. But if there are no competing offers, the existing customer is entitled to continue the transportation service for whatever term it chooses.[265] Therefore, an existing holder of capacity is entitled to continue to receive transportation service upon expiration of a long-term contract, but not necessarily on a short-term basis, unless there are no other customers bidding on the capacity.

Several LDCs and state agencies argue that the right of first refusal should apply to the price term only, *i.e.*, that the bidder should be required only to bid the highest Commission approved rate.[266] These parties argue that while it may be appropriate to make the LDC pay the highest cost-based rate, it would not be appropriate to require them to match the term for contract duration. Otherwise, these parties assert, bidding wars will result in excessively long contracts, tying up capacity, contrary to the

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265. Although if the extended term is one year or less, it will be subject to the pregranted abandonment authorized for short-term transportation contracts upon expiration of the contract.

266. *E.g.*, Niagara Mohawk Power Corp., Baltimore Gas and Electric Co., Cascade Natural Gas Corp., Long Island Lighting Co., and Minnesota Dept. of Public Service.

goals of the rule.[267] Furthermore, several parties argue that LDCs cannot reasonably be expected to know their requirements beyond 10 years.

Others argue that the maximum term required to be matched should be limited to a specific period, which, when elected, would automatically entitle the existing customer to continued service. Distributors Advocating Regulatory Reform (DARR) suggests a term of three years; Central Illinois Public Service Company suggests a term of ten years; and Consolidated Edison suggests a minimum term of five years.

The Commission will require existing customers to match the length of competing bids for capacity under expired contracts, as well as price, in order to retain the capacity. This proposal strikes the appropriate balance between the needs of customers for continued service and the benefits of competition in establishing the terms of service. In the first instance, the parties have control over the timing of pregranted abandonment as to their contracts and can defer the abandonment of the pipeline's service obligation by including a roll-over or evergreen clause.[268] Absent such a contractual provision, other shippers desiring the service may compete for it. Existing customers may have the greatest need for continuation of firm transportation under their expiring contracts, and continuation of that service to them may be the most efficient use of the capacity. The rule assures them this opportunity. But there must also be an

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267. *E.g.*, comments of Distributors Advocating Regulatory Reform.

268. Pipelines are not required to include rollover or evergreen clauses in transportation contracts, but if they do so, these clauses must be offered on a nondiscriminatory basis for all shippers, consistent with existing Commission policy.

opportunity for other shippers desiring the capacity to submit competing bids, which the existing customer can then match or not. This process affords an efficient, market-sensitive means of comparing the needs of the existing customer to those of competitors for the capacity, and measuring whether or not the public convenience and necessity requires that service should be continued to the existing customer.

While the limitation on price, to a rate that recovers only properly allocated costs, precludes differentiating among customers offering the maximum rate, there need be no such limitation as to length of the contract term. Other things being equal, a pipeline would prefer a longer term contract for service at the maximum rate than a shorter term. Other things being equal, the satisfaction of long-term transportation needs should have priority over the satisfaction of shorter-term needs. Accordingly, the Commission sees no reason to establish some maximum contract term, beyond which existing customers would not have to obligate themselves in order to retain firm capacity. This is particularly true in view of the capacity releasing mechanism adopted in the final rule which establishes a mechanism for the firm shipper to release unused capacity.

c. Mechanics of the Process — Post-Restructuring Proceedings

Many parties have asked the Commission to clarify the mechanics of exercising the right of first refusal that will apply after the initial restructuring proceedings. For example, several ask whether customers have one opportunity to bid or if it is an iterative process.[269] Kansas Power and Light Company suggests

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269. *E.g.*, Interstate Power Co. and New Jersey Natural Gas Co.

that the capacity holder should be able to wait until the bidding process is completed and then decide whether to match the most favorable bid.

At the outset, the right of first refusal is not a new, untested concept in gas regulation. The NGPA provided rights to purchasers of certain gas removed from the Commission's jurisdiction. Section 315 of the NGPA provides for a right of first refusal at the expiration of a contract for the first sale of natural gas to the person who, but for deregulation, would have been entitled to receive the gas. The right of first refusal under the NGPA gives the original purchaser the right to match the terms of a third party offer to purchase the gas at the expiration of the contract. If the original purchaser refused to match the terms of the third party offer, then the seller could sell the gas to the third party under the terms of the offer. Once the gas had been sold to the third party pursuant to the offer, the seller had no further obligation to the original purchaser.

The right of first refusal under this order will work similarly. When the contract is nearing expiration, the pipeline may seek offers from other persons interested in receiving the transportation. As discussed above in connection with capacity releasing, the pipeline is required to post available capacity and terms and conditions on its electronic bulletin board. If several offers are received, the pipeline will select one of the offers as the offer it will accept if the existing customer chooses not to match its terms. The pipeline will then present this offer to the existing customer, which, if it chooses to match the terms of price and duration, will continue to receive the transportation service from the pipeline. If the existing customer elects not to match those terms of the offer, then the pipeline must provide transportation service to the third party under the terms of the

offer. If, in fact, transportation is not provided pursuant to the offer with respect to both rate and term, then the original customer is entitled to continued service at the pre-existing rate.

Offers may present different benefits to the pipeline. For example, a pipeline could receive an offer to purchase transportation for a period of five years at the maximum lawful rate, and a second offer to purchase transportation for ten years at a rate less than the maximum. The Commission is not specifying in this order the appropriate method of determining which is the "best" offer. The parties must consider methods of evaluating offers, such as, for example, calculating net present value, in the restructuring proceedings. The mechanics of the right of first refusal must be developed in the restructuring proceeding and set forth in the tariff including a provision that will implement an appropriate method of determining which is the "best" competing offer.

d. Bona Fide Offers

Other commenters[270] are concerned about the integrity of the right-of-first-refusal process. They fear that pipeline affiliates could artificially bid up the transportation rate. They assert that the standards of conduct applicable to pipelines with marketing affiliates, and the NOPR's proposal to apply those standards to pipelines' marketing divisions, would not prevent this, and state that the pipeline should be required to demonstrate that an offer is *bona fide.*

As discussed above, parties can protect themselves from

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270. *E.g.*, Midwest Energy, Inc. and Distributors Advocating Regulatory Reform.

these concerns through contractual provisions. However, the Commission recognizes that disputes may arise about whether a third-party bid for capacity under an expired contract is *bona fide*. Parties to the restructuring proceedings should address this issue and develop procedures for distinguishing between *bona fide* and spurious offers. For example, it may be appropriate for a third-party bidder to post a bond, or pay a reasonable "down payment" when it tenders its bid.

e. Offers for a Portion of Existing Customer's Capacity

TransCanada Pipeline, Ltd. asks the Commission to clarify that when an existing customer exercises its right of first refusal to retain capacity under an expiring contract the competing bidder must bid for all of the capacity under the existing customer's contract, not just a portion of it. If, for example, an LDC had a contract demand of six million MMBtu's per day under an expiring contract, any competing bidder would have to bid on all of the capacity under the contract to trigger the LDC's obligation to match the offer in order to retain the capacity. If a competing bidder sought anything less than the total capacity under the expiring contract, the existing customer could ignore the offer and retain the capacity.

The Commission clarifies that competing bids must be matched by existing customers, even if they are for less than the total capacity reserved under the existing customer's contract. The policy urged by Transcanada would virtually insulate the very largest holders of transportation capacity from the bidding process. On the other hand, the fact that a competing bidder has bid the maximum rate for a very long term for only a portion of the capacity under an existing customer's contract

does not mean that the existing customer must match that offer for the remaining capacity. The existing customer need only match the competing bid for the amount of capacity to which the bid applies. If, for example, there are no other bids for the remaining capacity, the existing customer would simply proceed to negotiate the terms of a renewed contract for that capacity with the pipeline, without regard to the terms it had to match to retain the capacity for which there was a bid.

f. Converted Sales

As explained above, in *AGA II,* the court remanded the issue of pregranted abandonment of transportation service under section 284.221(d) of the Commission's regulations. On remand, in Order No. 500-J,[271] the Commission stayed the operation of this regulation where a customer converts firm sales service to firm transportation service after February 13, 1991.[272] The result was that these converted transportation arrangements would never be subject to pregranted abandonment and may be abandoned by the pipeline only upon receipt of Commission approval under Section 7(b) of the NGA.

Several commenters ask the Commission to clarify that conversions that have occurred during the effectiveness of the stay of pregranted abandonment under Order No. 500-J will never be subject to pregranted abandonment, nor have to exercise a right of first refusal to avoid pregranted abandonment. These parties note that while the NOPR states that transportation converted from sales during the period the stay is in effect would

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271. III FERC Stats. & Regs. ¶ 30,915 (1991).

272. *Id.* at p. 30,083.

remain subject to traditional section 7(b) abandonment, the text of the proposed regulation does not reflect this.

The Commission clarifies that conversions that took place during the effectiveness of the stay, *i.e.*, from February 13, 1991, to the effective date of the regulations promulgated in this order, will never be subject to pregranted abandonment. The revised section 284.221(d) specifically so provides. The Commission will require the pipelines to notify the Commission of all transportation arrangements that resulted from conversions during this stay in each pipeline proceeding implementing this rule. The stay is terminated on the effective date of this order.

Peoples Natural Gas Company argues that this provision discriminates in favor of conversions that took place during the effectiveness of the stay. However, the Commission finds that no one is aggrieved by this provision because, as explained above, the parties can defer pregranted abandonment by including an evergreen or roll-over clause in the contract. Absent such provisions, customers are protected by the right of first refusal. In sum, the rule contains sufficient safeguards so that customers that convert under these rules can be in essentially the same position as those that converted during the interim period.

XI. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

The Commission recognizes that the natural gas industry cannot get to the new regime required by this rule in an instant. Contracts, and certificate obligations, will have to be renegotiated, revised, and in some cases, terminated. Pipelines will have to design rates to reflect their restructured services

and incorporate the straight fixed variable rate design method. The transition to fully unbundled pipeline services will entail certain costs, and pipelines will need to propose mechanisms for recovery of those costs during the transition period. In this section, the Commission will discuss some of the issues that arise in connection with the transition, and the schedule and procedures to be used for an orderly and expeditious implementation of this rule.

A. Adjustment of Purchase Obligations and Firm Capacity

1. The Need for Adjustments

The restructuring required by this rule will result in significant changes to pipelines' services and rate structures, so that contractual commitments by pipelines and their customers must be subject to reevaluation and possible adjustment in view of those changes. Contracts entered into under significantly different regulatory conditions than those established by this rule, and under market conditions that in many cases were substantially different than today's, cannot be presumed to be just and reasonable under the regulatory structure established by this rule. Thus, pipelines and their customers that entered into long-term sales agreements when there were few if any reliable alternatives for the customers, or long-term firm transportation agreements, will have opportunities to adjust their commitments in light of the new commercial realities established by this rule and current market conditions.

The Commission finds that the continued enforcement of a pipeline sales customer's purchase obligations, agreed to before implementation of unbundling under this rule, is unjust and

unreasonable, and unduly discriminatory. Therefore, during the restructuring proceedings established by this rule, unbundled sales customers will be permitted to reduce or terminate, in whole or in part, their purchase obligations under contracts with their pipeline suppliers. Such contracts were entered into when the pipeline had a virtual monopoly over the provision of reliable "no-notice" sales service, because of the unavailability to other shippers of the storage and load balancing services necessary to provide such service, and the numerous restrictions placed on transportation service for gas sold by nonpipeline merchants. Customers are therefore authorized to reduce or terminate their sales purchase obligations under such contracts as a remedy, to afford them access to the competitive gas market, and the Commission is granting pipelines abandonment authority to reduce or terminate their sales obligations in accordance with their customers' elections.[273]

In addition, with the conversion to unbundled transportation and sales services current pipeline firm sales and transportation customers may decide that they no longer need to retain the same quantity of firm transportation as previously. Most firm capacity holders under existing contracts are obligated to pay the maximum transportation rate. Thus, existing firm capacity holders will need to reassess their future needs for capacity. As a result, the customer may no longer need the same level of

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273. Without the assignment of supply contracts, which must be done without undue discrimination, a customer's reduction in purchase obligations will likely result in the incurrence of costs by the pipeline. The pipeline will have the opportunity to recover these costs, either in the form of reservation fee surcharges on future transportation service, a negotiated "exit fee," or some combination. To avoid these charges or fees, the Commission strongly urges the customers to enter into negotiations to assume supply contracts. See *infra*, under discussion of transition costs and recovery mechanisms.

transportation from a certain pipeline, for example, because of capacity that becomes available on another pipeline. As another example, a current sales customer may decide that after conversion to unbundled firm transportation and unbundled sales it no longer needs, or wants, to maintain firm capacity rights from the beginning to the end of the mainline, but rather, only needs firm rights from a certain pooling point or market center that may be developed during the restructuring proceeding.

During the restructuring proceedings all firm capacity holders must reexamine the amount of firm capacity that they will need, or want, to continue to hold in light of the new services and rates to be developed to comply with this rule. Also, in order for the pipeline to develop the rates and range of services it will offer after restructuring, it will need to know whether and how much capacity its current firm capacity holders will continue to hold. Therefore, all firm capacity holders must participate in the restructuring proceedings and notify the pipeline of the amount of capacity they intend to continue to hold after restructuring.

Capacity that is no longer wanted by the current holders can be reallocated during the restructuring proceedings as follows: All firm capacity holders must notify the pipeline of the amount of capacity they intend to retain after restructuring, at the pipeline's proposed maximum rate or at an existing discounted rate, if no other shipper is prepared to bid for that capacity.[274] Where the pipeline has a queue for firm service, the pipeline must notify the current firm capacity holder if another shipper is prepared to bid more than the current capacity holder

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274. As discussed more fully below, certain shippers by contract are not obligated to pay the pipeline's maximum rate.

pays for that capacity. In that event, if the firm capacity holder is unwilling to pay up to the maximum rate to retain its existing capacity rights, the firm capacity holder must give notice that it wants to reduce or terminate its contractual rights to firm service. If the capacity holder makes that election, the pipeline is granted an automatic abandonment of its service obligation under Section 284.14(e) to the extent of such reduction or termination, so that it can reallocate the capacity to another shipper. This mechanism can be invoked unilaterally by an existing firm capacity holder to relinquish all or a part of its firm capacity *only* if there is a demand for the capacity and another shipper is prepared to bid for that capacity. Where there is no competing bidder for the capacity, the existing customer's rights and obligations under the existing contract are unaffected, since this provision is designed only to ensure an efficient allocation of capacity where there is unsatisfied demand for the capacity. Thus, it provides a limited opportunity for transportation CD reductions.

However, if an existing firm capacity holder wants to relinquish all or part of its existing capacity, but there are no competing bidders, nothing in the final rule precludes the pipeline and the capacity holder from negotiating CD reductions. For example, the pipeline and the shipper may agree to terminate or reduce CD upon the capacity holders' payment of a reasonable exit fee.[275] If this occurs the Commission will give effect to this agreement, including effectuating the parties' deal by granting abandonment of the pipeline's obligation.

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275. An exit fee is reasonable if it provides compensation to the pipeline for all the costs attributable to the departing customer so that the pipeline will not seek to allocate any unrecovered balance of the costs attributable to the departing customer to remaining customers. *See* Northern Natural Gas Company, 59 FERC ¶ 61,003 (1992).

Appendix B

Where there is unsatisfied demand for capacity, a firm capacity holder should not continue to receive service at a discounted rate, if another shipper is prepared to bid more, up to the maximum rate, for that capacity. Unless the pipeline is contractually precluded from charging the maximum rate, when there is unsatisfied demand for capacity, the pipeline must charge the highest price (up to the maximum rate) bid for that capacity. Any other pricing behavior is inefficient and unduly preferential to the shipper receiving the discount. Therefore, while the Commission will not adopt the proposal contained in the NOPR, during the restructuring proceedings, pipelines must reduce or eliminate any discounts up to the maximum rate for firm transportation in such circumstances, unless the pipeline is contractually precluded from charging the maximum rate.[276] The maximum rate, up to which a current firm shipper must be prepared to pay where there is unsatisfied demand for the capacity, is the maximum rate the pipeline is authorized to charge the current firm shipper for delivery to that shipper's existing delivery point. A competing bidder must be prepared to pay up to the maximum rate the pipeline is authorized to charge the competing bidder for delivery to that bidder's proposed delivery point. The current firm shipper only needs to bid up to its maximum rate.

Where the parties have negotiated and included in their contract either a fixed rate or some permanent form of discount, such as ninety percent of the maximum rate, the Commission recognizes the importance of giving effect to each party's

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276. Although the Commission may permit utilities to increase rates above the level agreed to in a fixed rate contract if it finds those rates so low as to adversely affect the public interest, FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956), there is no basis in the record of this proceeding for making generically applicable findings to that effect.

respective contract rights. This is consistent with the general purposes of this rule, to give parties the ability to control their transactions as much as possible through their contracts. Where such contracts exist, the Commission recognizes that it is not unduly preferential for the pipeline to continue to charge the discounted rate.

To facilitate this capacity reallocation process, the Commission has included in this rule a special abandonment provision to permit the reallocation of transportation capacity during the restructuring period. Generally, under Section 284.221(d) the pipeline is permitted to abandon transportation service where a contract expires or is terminated by the parties. However, Order No. 500-J stayed the effect of that provision for certain firm contracts so that the pipeline would have to file individual abandonment requests for transportation service under those contracts. Under new Section 284.14(e), the pipeline is granted automatic abandonment of its transportation obligations to correspond to any election by a current firm capacity holder to relinquish some or all of its existing firm capacity during the restructuring proceeding, as discussed above. This provision will permit the speedy abandonment and reallocation of transportation rights and obligations during the restructuring proceedings where the firm transportation rights were acquired during the period of the Order No. 500-J stay.

The Commission proposed in the NOPR that firm capacity holders could retain long-term transportation capacity under existing contracts only by exercising a right of first refusal during the restructuring proceedings, *i.e.*, by agreeing to match the price (up to the maximum) and most favorable (longest) term offered by any competing bidder. The purpose of this proposal was to require all parties to existing contracts for long-term

transportation service and bundled sales service to re-evaluate their need for firm capacity in view of the new unbundled service options and restructured rates. The Commission has changed these provisions in this rule and has included a mechanism to facilitate the orderly reallocation of capacity as described above.

The NOPR also proposed to permit pipelines' unbundled firm sales customers to reduce or terminate, in whole or in part, their firm sales entitlements (purchase obligations) during the restructuring proceedings. The final rule incorporates that proposal without change. Only the sales customer has the option to reduce or terminate sales service, not the pipeline. A pipeline's obligation to provide sales service continues, to the extent its sales customer elects to continue receiving sales service, for the duration of the existing sales contract. The automatic abandonment of the pipeline's obligation to provide sales service, granted in section 284.14, only applies to the extent the pipeline's sales customers elect to reduce or terminate, in whole or in part, sales service from the pipeline during the restructuring proceeding. After the initial restructuring, the provisions of the new blanket sales certificate will apply.

Parties will have to make decisions concerning their rights to adjust their service under the provisions of this rule in the course of the restructuring process, which will necessarily be iterative. A pipeline will propose a menu of unbundled services after discussions to determine the needs of its customers and other interested parties. The pipeline will need to estimate the extent that customers will use the restructured services and develop *pro forma* rates to recover its cost of service. Customers will review the pipeline's proposed services and rates and estimate their levels of usage. The pipeline may need to revise its proposed rates, and perhaps its menu of services, in response

to the initial indications of demand. Customers (or potential customers) that want additional transportation capacity will submit bids for that capacity at rates within the maximum and minimum rates proposed by the pipeline. As the process nears completion, sales customers will have to elect whether to continue buying gas from the pipeline on an unbundled basis at the same level as under their existing contracts. As described above, all long-term firm capacity holders (including formerly bundled sales customers) must notify the pipeline of the capacity they intend to retain, reduce, or terminate. In the end, gas supply and capacity will be reallocated in accordance with the needs of customers in an unbundled environment, where customers will have a range of choices not previously available.

The Commission expects and requires all parties — pipelines, producers, LDCs, end-users, state commissions, and others — to participate in the restructuring proceedings to reach this objective. Moreover, the Commission will require the discussions taking place during the restructuring proceedings to be conducted in an open and nondiscriminatory manner as to all parties. However, the Commission will permit restructuring discussions to take place outside of the Commission's offices.

2. Discussion of Comments

Many LDCs and industrial customers objected to the proposal to jeopardize their long-term transportation arrangements by requiring them to match competing bids to retain capacity. Some LDCs argue that this procedure will drive up their costs by forcing them to compete with industrial bidders that do not have any public service obligation.[277] Many industrial

277. *See, e.g.*, Citizens Gas and Coke Utility, Interstate Power Company, Panhandle Customer Group, and UGI Corporation.

customers and electricity generators protest the prospect of having to pay higher rates after having structured financial arrangements on the basis of negotiated transportation rates, especially those that have recently negotiated long-term contracts for firm transportation service at discounted rates.[278]

These provisions have been changed in the final rule. However, the Commission's goal is still to effect a more efficient allocation of capacity. Where the demand exceeds available capacity, and another shipper is prepared to bid up to the maximum rate for that capacity, the pipeline must charge the highest rate bid up to the maximum fully allocated, cost-based rate for the capacity. If existing capacity holders have not negotiated fixed discounted rates for that capacity, then they must be prepared to pay up to that rate or release the capacity to other shippers that are willing to pay up to the maximum rate.

As noted above, most LDCs with contracts for bundled sales service are currently paying fully allocated, cost-based rates for the embedded transportation service, which is the equivalent of the maximum rate for open access transportation. For capacity converted under the transitional provision of this rule (18 CFR 284.14), the only question is whether LDCs will have the opportunity to negotiate for a discounted transportation rate in the process of the pipeline's unbundling and restructuring. If there are competing bidders willing to pay the maximum rate for the capacity, the LDCs will not have that opportunity. If there are no competing bidders, or none willing to offer the

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278. *E.g.*, Midland Cogeneration Venture Limited Partnership, New England Power Company, Southern California Edison Company, Thermo Electron Corporation, Agricultural Mineral Corporation, The Fertilizer Institute, Mississippi Chemical Corporation, Process Gas Consumer Group *et al.*, and Reynolds Metals Company.

maximum rate, LDCs can negotiate for a discounted rate. All other shippers with firm transportation capacity at discounted rates will also have to match competing bids, unless they have fixed-rate contracts. If shippers have long-term contracts for firm transportation with fixed-rate provisions that are below the maximum rate, they will not have to pay the maximum rate or match competing bids to retain their capacity. Nor will customers that receive transportation under individual certificates, rather than Part 284 open access blanket certificates, have to match competing bids, because the provisions of this rule do not apply to such service.

The Panhandle Pipeline Group argues that there are no findings or facts to support the proposal to permit sales customers to have the unilateral right to reduce their purchase obligations under their sales contracts, and note that the Commission's attempt to allow such unilateral reductions in Order No. 436 were expressly rebuffed by the court in *AGD I*[279] Pacific Gas Transmission Company urges the Commission to honor all existing firm service agreements between pipelines and their customers, absent a case-specific finding that a particular contract is unduly discriminatory, or otherwise anticompetitive or contrary to the public interest. Natural characterizes the proposal in the NOPR as giving a pipeline's customers the right to abrogate existing firm sales contracts with their pipeline suppliers, which it opposes as one-sided and disruptive. Columbia and Natural argue that if customers have the right to revise their contractual obligations to purchase gas, pipelines should also have the right to reduce or eliminate their obligations to sell gas.

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279. Associated Gas Distributors v. FERC, 824 F.2d 981, 1013-21 (D.C. Cir. 1987), *cert. denied sub nom.*, Interstate Natural Gas Association of America v. FERC, 485 U.S. 1006 (1988).

Columbia states that its primary concern with the NOPR involves the one-sided nature of the contract renegotiation process for sales service. Columbia notes that pursuant to its recent global settlement,[280] Columbia entered into sales agreements with its wholesale customers to provide approximately 360 Bcf of sales service annually through the year 2004. Under the terms of the NOPR, according to Columbia, its sales customers would be able to pick and choose the precise level of sales service they desire, while Columbia would not be given any similar opportunity.

Natural points out that it entered into new contracts effective December 1, 1990, at a time when the essential framework of open access transportation was in place on its system. Natural asserts that the new contracts are for limited terms of not more than five years, and that it has made (or retained) supply commitments with producers based on these sales contracts with its LDCs. According to Natural, the Commission's "wholesale abrogation" approach tests the limits of the Commission's authority, and undermines the confidence of parties in the efficacy of contracts subject to regulation by the Commission. Natural argues that if customers abrogate these contracts pursuant to the final rule, Natural should be guaranteed total recovery of any resulting costs.

The Commission recognizes that the customers of Columbia and Natural may have had more choices than some other customer groups during the recent, post open-access renegotiations of sales contracts. Nevertheless, neither Columbia nor Natural currently offers fully unbundled transportation and storage services of a quality equal to that embedded in their

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280. *See* Columbia Gas Transmission Company, 49 FERC ¶ 61,071 (1989), *reh'g denied*, 51 FERC ¶ 61,194 (1990).

firm sales service. Thus, their customers were still subject during the recent contract negotiations to the pipelines' monopoly over reliable, no-notice delivery service for which the customers' right to adjust purchase obligations is a remedy.

However, the Commission has crafted a rule that balances the interest of the pipelines and their customers by permitting pipelines to abandon firm sales obligations where customers elect to reduce or terminate purchases, and to recover 100 percent of any gas supply costs, as Natural urged, incurred as a result of their sales customers' elections. Knowing that the pipelines will be entitled to 100 percent recovery of the costs of realigning their gas supply contracts (described *infra*), purchasers must exercise considerable prudence in deciding whether to exercise their rights under this rule to reduce or terminate their purchase obligations. This is an area where cooperation between a pipeline and its sales customers can minimize the transition costs. For example, customers can postpone the effective date of their reductions of purchases from the pipeline to correspond to the term of certain of the pipeline's producer supply contracts that would have to be renegotiated, thus giving rise to transition costs, if the customers terminate purchases. However, the customer will be making these decisions in the context of the restructuring proceeding. In order for these choices to be meaningful, the pipeline must put on the table the full range of unbundled services, and the estimated rates for those services, that it expects to offer to comply fully with the final rule. Only then can customers make rational choices and elect the services that meet their needs.

Appendix B

B. Transition Costs and Recovery Mechanisms

1. Summary and Rationale

The Commission recognizes that pipelines will likely incur costs as a result of implementing the requirements of this rule. The issues are how, to what extent, and from whom, should the pipelines recover those costs.

The Commission envisions four types of costs. The first type are the unrecovered gas costs (or credits) remaining in the purchased gas adjustment (PGA) Account No. 191 when a pipeline adopts market-based pricing for its gas sales and terminates its purchased gas adjustment mechanism (the "Account No. 191 balance"). The second type of costs may result from the pipelines realigning their existing gas supply contracts with producers in connection with implementing this rule ("gas supply realignment costs"). A third type are the costs of a pipeline's assets now used to provide bundled sales service, such as gas in storage, and capacity on upstream pipelines, that cannot be directly assigned to customers of the unbundled services ("stranded costs"). A fourth type consists of costs associated with physically implementing the rule (*e.g.*, meters, valves, communications equipment)("new facility costs").

Under market-based rates, the pipeline would no longer recover gas costs through a PGA mechanism, but it may have unrecovered gas costs in Account No. 191 when it discontinues that recovery mechanism. The Commission will permit pipelines to "direct bill" the Account No. 191 balance to their former bundled, firm sales customers, as proposed in the NOPR, whether or not the customers elect to continue as firm sales customers on an unbundled basis after implementation of this

rule. The unrecovered gas costs should not be billed to customers who are not sales customers during the period when liability for the direct bill is established, because the gas purchase costs are not incurred for them and they would not have to pay those costs if the PGA were to continue. Furthermore, customers would have the right to challenge the prudence of the gas purchases reflected in the Account No. 191 balance.[281]

The unrecovered gas costs are not future costs incurred to comply with the rule, but are costs incurred prior to implementation of the rule.[282] The Commission's proposal in the NOPR that the underrecoveries in Account No. 191 would be direct billed put pipeline customers on notice that they would have to pay any such costs accrued after July 31, 1991, the issuance date of the NOPR. The Commission reiterates that pipeline firm sales customers will be responsible for unrecovered gas costs in Account No. 191 accrued prior to implementation of this rule. Customer responsibility for commodity-related Account No. 191 costs may be based on their gas purchases for the twelve months preceding the effective date of service under the pipeline's unbundled sales certificate (granted under § 284.284), and for unrecovered demand charges in Account No. 191, based on contract entitlements on the day preceding that effective date.[283] The pipelines must permit customers to

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281. *See* Transcontinental Gas Pipe Line Corp. 46 FERC ¶ 61,364 at p. 62,147 (1989).

282. The costs are incurred prior to implementation when the gas is taken prior to implementation, even though paid for afterwards. For example, there may have been a billing dispute. *See Id.* at p. 62,147.

283. Pipelines or other parties to the restructuring proceedings may propose other mechanisms if the above described mechanism is inequitable

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pay the direct bill in either a lump sum, over twelve months or over some other reasonable period of time, at the customer's option.[284] Of course, a pipeline must refund any overrecoveries in its Account No. 191 and flow through to its customers any refunds it receives that are attributable to the relevant past period.

The second type of costs, gas supply realignment costs, may result from the pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers in connection with implementing this rule. The Commission will permit pipelines full cost recovery of prudently incurred gas supply realignment costs deemed to be eligible under this rule. To recover those costs, a pipeline will be permitted to use either a negotiated exit fee, or a reservation fee surcharge recoverable from Part 284 firm transportation customers.

Under this rule, a firm entitlement holder has options as to how to react to gas supply realignment costs: it may remain a sales customer of the pipeline; otherwise, it may take an assignment of the pipeline's existing contracts or pay an exit fee/reservation fee surcharge for costs approved by the Commission. To mitigate any transition costs that may arise, the Commission strongly recommends assignment of gas supply contracts. Unless the specific gas supply contracts prohibit assignment, the pipeline would assign those contracts on a non-

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(Cont'd)
— if for example, there are large underrecoveries but very few customers were making purchases during the base period.

284. Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364 at p. 62,147 (1989); Northwest Pipeline Corp., 45 FERC ¶ 61,224 (1988), *reh'g granted in part*, 46 FERC ¶ 61,091 (1989).

discriminatory basis to those who choose to receive assignments.[285]

If there are excess gas supply contracts held by the pipeline after assignment, the pipeline should realign those contracts. Where the pipeline remains in the merchant business, it should realign its portfolio to leave it at a market responsive level, enabling it to compete on a even basis with any other merchant. The Commission, in a Section 4 filing by the pipeline to recover gas supply realignment costs, will perform two levels of review.

The first level will be an eligibility review to determine whether the resulting realignment costs are attributable to events which occurred independently of the final rule, or whether they are attributable to the implementation of the final rule. That proportion of gas supply realignment costs which are determined to be attributable to the final rule will be eligible for 100 percent cost recovery if the Commission finds that the costs were prudently incurred. If the Commission finds that a portion of the gas supply realignment costs are attributable to events that are independent of the final rule, then it will treat such costs accordingly and continue the use of the recovery mechanism developed in Order No. 528. Where the total sum of gas supply realignment costs is partially eligible and partially non-eligible, parties should devise an allocation method which divides the costs among the two recovery mechanisms proportionately.

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285. Although the Commission will not prescribe a certain assignment/allocation mechanism, it expects the parties to adhere to non-discriminatory principles that will result in equal treatment for all potential assignees regardless of whether they are sales customers of the pipeline. The Commission expects assignments to minimize the costs that will be recovered in a reservation fee surcharge to the fullest extent possible.

Appendix B

The second level of review will be for prudence. In any rate filing, all costs are subject to prudence review; the Commission is not proposing a new standard under this rule. The Commission's primary objective in any prudence review of gas supply realignment costs will be to determine that the total amount is as minimal as possible. Elements of this determination should include, but not be limited to, the following: whether the contract terms were reasonable in light of the market conditions existing when the contract was negotiated, renegotiated or terminated, whether the contract realignment costs resulted from vigorous arms-length negotiations, and whether there was a *bona fide* effort on the part of both parties to the contract to arrive at a settlement.

The Commission will permit prudently incurred gas supply realignment costs to be recovered by use of a reservation fee surcharge or an exit fee. A surcharge mechanism will be in addition to a pipeline's reservation charge for firm transportation and storage services, and will thus be recoverable from all Part 284 firm transportation customers. The surcharge will not be applicable to interruptible transportation service or transportation under individual NGA Section 7(c) certificates. Parties may also negotiate for the payment of an exit fee, in lieu of, or in combination with, a reservation fee surcharge. The exit fee could be a cash payment made by a sales customer that reduces or terminates its sales obligation during the restructuring proceeding.

The pipeline and interested parties may negotiate allocation of gas supply realignment costs among the pipeline's various firm services in the restructuring proceedings. The Commission will not specify a method for allocating such costs. Although the Commission will not require a sunset date for a reservation

fee surcharge for gas supply realignment costs, all parties to the restructuring proceedings are encouraged to consider terminating the surcharge on a date certain.[286]

In the NOPR, the Commission noted that take-or-pay costs and buyout/buydown costs have been recoverable under the provisions of Order No. 528, where pipelines agree to absorb at least 25 percent of such costs, unless the pipeline has implemented a market-based price for its gas sales. The NOPR proposed that pipelines be able to continue to seek recovery of such costs through an Order No. 528 mechanism after restructuring, if they did not implement a market-based price for gas sales. The NOPR sought comment on whether some other mechanism would be more appropriate, with or without an absorption requirement, for recovery of gas supply realignment costs that result from compliance with this rule.

After considering the comments on this issue, the Commission has concluded that pipelines should be entitled to recover 100 percent of their prudently incurred gas supply realignment costs that result from compliance with this rule. However, the Commission will not allow the pipelines to recover 100 percent of the costs until the Commission determines they have fully complied with the final rule. Thus the policies of Order Nos. 500 and 528, under which pipelines absorbed a percentage of take-or-pay costs will generally not be applicable

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286. While not imposing a sunset date, the Commission will, three years after the effective date of this rule, audit each pipeline's remaining gas supply contracts to ensure that the pipeline has sought, with due diligence, to realign its contracts to reflect its obligations brought about by this rule. If pipelines and their customers agree to a sunset date for filing for recovery of new gas supply realignment costs within this three year period, the Commission will not audit that pipeline's gas supply contracts.

to recovery of gas supply realignment costs attributable to this rule,[287] although the policies of Order No. 528 will continue to apply until the pipeline fully complies with the provisions of this rule.

The policies of Order Nos. 500 and 528 were designed to encourage pipelines to share some of the cost of the extraordinary take-or-pay liabilities of the early and mid-1980's. The Commission does not anticipate that pipeline gas supply costs that are incurred as a result of implementing this rule will approach the order of magnitude of the take-or-pay liabilities of that era. For one thing, pipelines should now have gas supply contracts that are more responsive to the pipelines' markets. Customers will undoubtedly weigh the effects of paying the gas supply realignment costs in deciding whether to reduce their purchase obligations to pipelines under currently effective contracts or to take assignment of their share of the pipelines' current contracts. Although pipelines will not be asked to bear any prudently incurred gas supply realignment costs they will incur as a direct result of the restructuring required by this rule, they will not be afforded protection from challenges to their prudence in this matter.[288]

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287. On the other hand, if a pipeline has filed for recovery of take-or-pay or contract realignment costs under Order No. 528, the policies of that order continue to apply to those costs. Such costs may not be recharacterized as costs attributable to the requirements of this rule.

288. Nor should LDCs' actions in restructuring proceedings be exempt from prudence challenges under applicable law in proceedings before state regulatory commissions. As the Commission stated in Order No 528-A: "[I]ts action in authorizing interstate pipelines to charge LDCs for take-or-pay costs should not be viewed as preventing action by the state commissions to require partial absorption of those costs by LDCs in accordance with federal and

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The third type of costs, stranded costs, are costs now incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services. For example, pipelines may retain unclaimed or unneeded upstream pipeline capacity even after assignment of portions of that capacity to their firm transportation customers. Similarly, the pipelines may have unbooked, open-access, contract storage beyond their storage needs for balancing and system management.

Stranded costs and the fourth type of costs, for new facilities, should be treated like all other prudently incurred costs, and the pipeline should file to recover such costs in a general rate filing under NGA Section 4. Including new facilities costs and stranded costs for consideration in a general rate case will permit a full review of their legitimacy, and case-specific decisions on how to allocate these costs. While the Commission anticipates that most of the costs of new facilities would be includable in rate base, and therefore affect reservation fees for transportation services or the demand charge component of other services, there is no way of anticipating the nature and amount of the stranded costs, and thus no way at this time of devising an appropriate billing mechanism on a generic basis.

2. Discussion of Comments

Most of the commenters, including LDCs, support the

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state law." Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 54 FERC ¶ 61,095 at p. 61,308 (1991). *See also* Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission, 837 F.2d 600 (3d Cir. 1988), *cert. denied*, 488 U.S. 941 (1988); and Pike County Light and Power Company v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-738 (1983).

ability of the pipelines to recover 100 percent of their prudently incurred transition costs, although no commenter proposed any specific, detailed, cost recovery mechanism.[289] Virtually all of the comments on transition costs addressed gas supply costs. Pipelines propose that recovery of gas supply costs, incurred to realign contracts with producers as a result of implementing this rule, should be through a direct bill or exit fee, not through a commodity surcharge, which they argue would put them at a disadvantage in a highly competitive market.[290] Producers also favor a direct bill mechanism, arguing that volumetric surcharges will result in lower netback prices to them.[291] On the other hand, LDCs and state commissions generally favor volumetric surcharges, and oppose direct bills, which they argue will encourage bypass by large industrial end users.[292] The California Public Utilities Commission argues for partial absorption of gas supply costs by pipelines as an incentive to minimize transition costs. Several LDCs propose that the Commission authorize pipelines to amend their contracts with producers to avoid the

289. *See, e.g.*, Associated Gas Distributors, Brooklyn Union Gas Company, and United Distribution Companies.

290. *E.g.*, Enron Interstate Pipelines, National Fuel Gas Supply Corporation, Natural Gas Pipeline Company of America, Tenneco Gas, and Panhandle Eastern Pipeline Group.

291. *E.g.*, Independent Petroleum Association of America, MESA Limited Partnership, Natural Gas Supply Association and Indicated Producers, and Yates Petroleum Corporation.

292. *E.g.*, Distributors Advocating Regulatory Reform, Michigan Consolidated Gas Company, Northern Indiana Public Service Company, New England Conference of Public Utility Commissioners, National Association of Regulatory Utility Commissioners, and Alabama Public Service Commission.

costs of supply no longer needed as a result of restructuring, and some suggest that producers' access to transportation service should be conditioned on granting the pipeline relief from its contractual obligations for such supply.[293]

The Commission is authorizing 100 percent recovery of prudently incurred gas supply realignment costs incurred as a result of the full implementation of the rule because of the further significant industry-wide restructuring imposed by the Commission in this rule. Any indication that pipelines were lax in their efforts to minimize gas supply realignment costs will be subject to a challenge for prudence and careful scrutiny by the Commission, as discussed above.

In Order No. 500 the Commission adopted rules to allow the pipelines to recover prudently incurred contract reformation costs. That program has been in place for over four years. Indeed, the Commission has found that the take-or-pay problem has been "substantially resolved."[294] The Commission is strongly encouraging pipelines to take additional steps, as soon as possible, to realign their obligations to sell gas resulting from customer choices brought about by this rule.

Pipelines must be able to show that any gas supply realignment costs for which they seek 100 percent recovery are attributable to their actions taken in response to this rule, and that such costs have been minimized by vigorous arms-length

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293. *E.g.*, City of Colorado Springs, Mobile Gas Service Corporation *et al.*, Northern Distributor Group, and Pacific Gas and Electric Company.

294. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. [Regulation Preambles 1986-1990] ¶ 30,867 at p. 31,523 (Order No. 500-H).

negotiations with their producer/suppliers. Thus the possibility of having to defend the incurrence of such costs, and suffer disallowance of recovery, should provide sufficient incentive for pipeline diligence in minimizing these costs.

A fixed surcharge on firm transportation reservation rates is selected (traditionally called a "demand surcharge"), because it passes through the pipeline's costs of adjusting its gas supply inventory to the customers whose choices give rise to the costs, and the customers that will benefit from the unbundling and restructuring required by this rule. The reservation fee surcharge mitigates some of the "net-back" effect on wellhead prices of a volumetric surcharge on all throughput, which might jeopardize the ability of producers to develop new gas supplies by lowering wellhead prices even more than current market conditions have already. The Commission has already explained in detail in Order Nos. 500-H and 500-I why it does not choose to try to revise producer contracts under NGA section 5.[295] While in Order No. 500-H, the Commission conditioned producers' access to transportation service on their willingness to give the pipelines certain credits against the pipelines' take-or-pay obligations, the Commission is very reluctant to create disincentives to producers to market their available reserves to willing buyers by requiring them to relinquish their contractual rights, or placing other conditions on their access to willing buyers in the marketplace.

Several LDCs and state commissions ask that an LDC not be assessed transition costs attributable to former industrial customers that have by-passed their system, and now receive

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295. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 (Order No. 500-H), *order on reh'g*, FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,880 (Order No. 500-I).

service directly from the interstate pipeline that serves the LDC.[296] The Commission will consider requests from LDCs for two forms of relief, where they can show a direct nexus between the by-pass and the costs at issue: (1) a reduction in an LDC's contract demand and reservation fee charges, with the industrial customer picking up the LDC's reduced portion directly, and (2) a transfer from the LDC to the industrial customer of the LDC's share of transition costs that are attributable to that customer. Although the Commission has denied similar requests for relief in the past,[297] and will not grant generic relief here to LDCs in this situation, it will consider requests for such relief concerning future transactions in the context of the new regime of this rule on a case-by-case basis.

3. Great Plains Gas

The Dakota Gasification Company (Dakota), the current owner of the Great Plains Gasification Project, which operates a plant for the conversion of coal into synthetic natural gas, requests that a special billing mechanism be authorized for any of the pipelines that purchase gas from the project, if they terminate their PGA mechanisms and implement market-based pricing of gas under this rule. The synthetic gas from Great Plains is priced substantially above current market clearing prices. Dakota also requests that the firm transportation capacity on such pipelines used for transportation of the synthetic gas

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296. Illinois Power Company, Tennessee Valley Municipal Gas Association, United Distribution Company, and Illinois Commerce Commission.

297. *See* Northern Illinois Gas Company v. Natural Gas Pipeline Company of America, 47 FERC ¶ 61,396 (1989), 48 FERC ¶ 61,337 (1989), 49 FERC ¶ 61,098 (1989), 56 FERC ¶ 61,215 (1991).

not be subject to abandonment in the restructuring proceedings. Dakota notes that the Commission recently approved a settlement in the restructuring proceeding of Transcontinental Gas Pipeline Corporation (Transco) that provided for a volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to its obligations to purchase synthetic gas from Great Plains.[298]

There are three other pipelines that purchase synthetic gas from Great Plains — ANR Pipeline Company, Natural Gas Pipeline Company of America, and Tennessee Gas Pipeline Company. The Commission will consider any proposals in these pipelines' restructuring proceedings for a special billing mechanism and special treatment for the associated transportation capacity for Great Plains gas consistent with the precedent in the Transco proceeding.

C. Schedule and Procedures

1. Summary

As proposed in the NOPR, the Commission intends to rely initially on the parties in the restructuring proceedings on each pipeline system to work out the details of compliance with this rule. To this end, the Commission is instituting restructuring proceedings (the RS proceedings) for each interstate pipeline affected by this rule by means of the notice issued contemporaneously with this rule. Section 284.14 is added to the general provisions of part A of Part 284, as a temporary provision to govern the implementation of this rule. The process of implementation thus begins with the issuance of this order

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298. Transcontinental Gas Pipe Line Corporation, 55 FERC ¶ 61,446 at p. 62,332 (1991).

and notice. Interested parties may file motions to intervene in each RS docket within 30 days after issuance of this rule. The pipeline or any other interested party may file a motion to consolidate the RS proceedings with any related pending proceedings within 45 days of issuance. In addition, if a pipeline believes that any part of its existing services, tariff provisions, and rates already comply fully with the provisions of this rule, it can inform the Commission at this time. The pipeline must support its belief with a detailed explanation of how its tariffs already comply with the different features of the rule. The Commission will act promptly to review any such claim so that the pipeline and other interested parties will know whether, and if so, what further action will be needed by the pipeline to fully comply with this rule.

No later than 60 days after issuance of this order, pipelines must initiate discussions on implementation of the rule with the intervenors in their assigned RS proceeding. Pipelines must serve each intervenor in their RS proceedings a summary of their proposals for full compliance with the rule, including *pro forma* rates, no later than 90 days after issuance of this order. Also, to facilitate timely and full compliance, the Commission's staff will convene a pre-filing conference in each RS proceeding, within a reasonable period of time after the pipeline's summary proposal has been served, but before the pipeline's deadline for making its compliance filing, to assist the parties in developing the full range of issues to be addressed on that system and structuring the shape of the compliance filings.

Each pipeline is assigned a deadline in the new section 284.14 and the companion notice for making its tariff filings to comply fully with this rule. The first group of filings will be due by October 1, 1992, and the three remaining groups of filings

are due by November 2, 1992, December 1, 1992, and December 31, 1992, respectively. These compliance filings should be made earlier than these deadlines, if possible. The effective date (or dates) of the full implementation of each pipeline's compliance will be subject to Commission approval on a case-by-case basis. The Commission will issue an order on each compliance filing, either accepting it for implementation on a prospective basis or establishing appropriate procedures. A timeline showing this implementation schedule is appended to this order. The Commission expects to act on all compliance filings in time for all pipelines to implement this rule sufficiently in advance of the 1993-94 winter heating season to provide customers with an adequate opportunity and adequate time to schedule necessary services for that season.

2. Discussion

As discussed above, the Commission has found that the current regulatory structure, and in particular the pipelines' existing bundled, city-gate, firm sales service, is and will continue to be an unreasonable restraint of trade which causes competitive harm to all segments of the natural gas industry because, among other things, it provides the pipelines with an undue advantage and subjects other gas sellers to an undue disadvantage. Therefore, the Commission has found that the pipelines' bundled, city-gate firm sales service violates Sections 4(b) and 5(a) of the Natural Gas Act. Accordingly, the Commission is adopting remedies that must be complied with as soon as possible to remedy the violations of the Natural Gas Act promptly and to eliminate the anticompetitive conditions that currently exist.

To that end, the Commission seeks to ensure that all

pipelines will be in full compliance with the final rule for the 1993-1994 winter heating season. While the Commission anticipates that many pipelines will be able to implement all required elements of the final rule in advance of the 1992-93 winter heating season, other pipelines may not be able to formulate specific proposals and complete their negotiation with all interested parties as expeditiously for various pipeline-specific reasons. Meaningful implementation of this rule on each pipeline system will require existing sales and transportation customers, competing gas merchants, and other interested parties to have an opportunity to consider the various sales, transportation and storage services that will result from the final rule, and to work out the operational details with the pipeline, sufficiently in advance of the winter heating season to permit the development of strategies for meeting peak season demand. At least for some pipelines, it appears unlikely that implementation of this rule would be complete in time for the 1992-93 winter heating season. Therefore, while the Commission strongly encourages compliance with this rule this calendar year, on balance the Commission has concluded that it should not require full compliance with this rule until the 1993-94 winter heating season. This will afford the pipelines and interested parties enough time to work out the operational details and make all adjustments necessary. The Commission does not anticipate any reason for further delay in implementation.

Considerable benefit will be realized from implementation of the final rule by all pipelines in the same general time frame, rather than staggered over several years. A coordinated implementation can facilitate the development of market centers, the allocation of capacity between upstream and downstream pipelines and their users, and the allocation of storage facilities. It will also permit market participants to develop more options

for the delivery of gas out of any given supply basin or into any given city-gate market using a single or multiple pipeline paths and storage combinations. Also, by starting now towards full implementation for the 1993-94 winter season, parties will be able to arrange for the full range of storage service options for that winter heating season, because the storage injection season begins as early as March 1 of the preceding spring for some pipeline systems.

Another side of enabling market participants to evaluate all service options contemporaneously, is that they can also evaluate all the costs associated with the available options, especially transition costs, and develop a strategy that will best mitigate the transition costs. In the Commission's view, reliance on well-informed customer choices is the best way to minimize transition costs, rather than delaying, deferring, or phasing-in critical elements of this rule.

The phasing-in of the requirements of this rule would not be consistent with the Commission's goals here. The unbundling of sales and transportation services makes it possible for the Commission to permit pipelines to sell gas under the blanket sales certificates on a basis analogous to unregulated sellers. It also enables the Commission to ensure that transportation and storage will be available for all gas supplies on equal terms. Unbundling in combination with the new no-notice transportation service, access to storage, the capacity release mechanisms, and other capacity adjustment mechanisms in this rule will enable market participants to function without the anticompetitive influences from the past regulatory environment. Unless these are all implemented in a generally contemporaneous time frame, past restrictions on the functioning of the market will continue, and the Commission's purposes here

may not be achieved within a reasonable period of time. More importantly, these provisions must be implemented contemporaneously in order for market participants to be able to replicate the bundled service provided by pipelines today. These considerations have guided the Commission's development of the implementation procedures and schedule discussed below.

The notice issued contemporaneously with this order assigns an RS docket number to each pipeline restructuring proceeding. If a pipeline believes that its existing tariffs or settlements already filed with the Commission achieve the full objectives of this rule, or that a proceeding currently pending before the Commission constitutes an appropriate vehicle for its compliance with this rule, it must file a motion in the RS docket with the Commission within 45 days after issuance of this order, setting forth the basis for its belief and indicating whether it wants to terminate the currently pending proceedings, consolidate them with the RS docket, or terminate the RS docket.

The Commission will act promptly to address any such requests, so parties can have the benefit of the Commission's views before they have to engage in discussion under the restructuring requirements of the rule. If the Commission agrees that any or all aspects of a pipeline's current services, tariff provisions, or rates comply fully with the rule, then there is no need for the parties to engage in the restructuring proceedings established here, or at least as to the aspects that already fully comply. The Commission may not be able to provide this guidance before the parties are required to begin discussion under the timetable established in this order. However, the Commission will endeavor to act on these filings as quickly as it can.

Appendix B

Motions to intervene in the restructuring proceedings after the pipelines' compliance filings to fully implement the rule are made will not be viewed with favor. The speed and success of implementation of this rule will depend largely on the involvement of all interested parties (including producers, shippers and potential shippers, marketers, state commissions, and end-users, as well as small, large, and medium-sized LDCs) in the discussions that will precede the pipelines' filings to comply with the rule, and the attempted intervention of interested parties after those discussions have culminated in the compliance filings will generally be disruptive.

The Commission encourages the pipelines to develop a consensus on, or substantial support for, their plans of full implementation before making the required restructuring filings, if possible. To this end, this order requires each pipeline affected by this rule to initiate discussions with its customers and other interested parties no later than 60 days after issuance of this order. Each pipeline must serve a summary of its proposed plan of full implementation to the intervenors no later than July 7, 1992, following the procedure used by the Commission's litigation staff for serving "top sheets" in a rate case. This summary must include a description of how the pipeline proposes to implement fully all aspects of the final rule, including any terms and conditions the pipeline proposes for maintaining operational control of its system and the reasons why the pipeline believes these are necessary, and *pro forma* illustrative rates for the restructured services.

Furthermore, the Commission is directing its staff to convene at least one conference in each restructuring proceeding prior to the pipeline's deadline for making its restructuring filing. These will be publicly noticed conferences, convened for the

purpose of assisting the pipeline and interested parties in delineating the issues that need to be resolved in the pipeline's compliance filing and to discuss the structure of that filing. The conference in each proceeding should be convened no sooner than 90 days nor later than 180 days after issuance of this order. The conferences may be convened at locations that are convenient to the representatives of the pipeline and intervenors, not necessarily at the Commission's headquarters in Washington, D.C. The Commission staff will report to the Commission, if needed, the status of pre-compliance filing discussions at the public conference to assist the Commission in identifying early any problems that may be hindering the full and timely implementation of this rule.

The nature of the pipelines' filings may vary somewhat, depending on the extent to which the pipeline has previously incorporated features required by this rule into its current tariff and portfolio of services. However, all of the pipelines' filings will be compliance filings pursuant to the Commission's findings and rulings in this final rule under Section 5 of the Natural Gas Act (NGA), and authorizations granted under NGA Section 7.

The Commission recognizes that some components of the restructured rates will be higher than the same component (or an equivalent component) under existing rates. However, the pipelines are required to submit *pro forma* tariff sheets that are based on the same cost of service and total throughput as their currently effective rates. Thus, the restructuring will not result in any overall increase in rates. Where changes in rate design result in rate increases in certain components of the rates, or to certain customers or customer classes, the Commission will permit the increases in the compliance filing because it is related

to a Commission directed modification in the pipeline's rate structure.[299]

Furthermore, pipelines may file notices of rate changes pursuant to Section 4 of the NGA in conjunction with their restructuring filings that have no direct relationship to the required restructuring, but simply reflect changes in costs or throughput. The pipelines may also seek rate increases due to implementation of this rule in a NGA Section 4 filing. However, whether filed to reflect changes due to restructured rate design or other things, such notices of rate changes should be filed separately from the restructuring filings, and will be assigned different docket numbers, because the effective dates of rate changes filed under Section 4 will not necessarily coincide with the effective dates of the restructuring filings.[300] Pipelines will not be permitted to implement contested features of their restructuring proposals prematurely by incorporating them in a separate Section 4 filing.

The pipelines should propose effective dates for their restructuring that will provide for full compliance sufficiently in advance of the 1993-1994 heating season, as discussed above. Many commenters have suggested that unbundling should not be implemented just prior to or during a peak-load season. As

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299. *See* ANR Pipeline Co. v. FERC, 863 F.2d 959 (D.C. Cir. 1988) (Commission can permit rate increases as part of compliance filing to implement Commission directed modifications under Section 5(a) of the NGA.).

300. Also, as discussed above, the final Policy Statement on Incentive Ratemaking will address the relationship, if any, between the final rule in these dockets and the filing of any incentive ratemaking proposals for non-competitive pipeline services.

discussed previously, the Commission concurs. Because the effective date of full implementation will not occur until the Commission accepts the tariff sheets in the compliance filing, the Commission will ensure that no pipeline has to implement the rule during a peak-load season.[301] The Commission strongly believes that all of the pipelines affected by this rule will be able to implement the full requirements of this rule for the 1993-1994 winter heating season. Thus, most pipelines should be fully unbundled in compliance with this rule by the spring or summer of 1993. In any event, the effective dates for each plan will be subject to Commission approval on a case-by-case basis, in view of the degree of support by interested parties and conformity to the goals and requirements of this rule. However, the Commission will not tolerate delays that would prevent implementation for the 1993-1994 heating season.

The compliance filings must address each and every feature of the restructuring required by this final rule and include a detailed explanation of how the pipeline intends to implement those features. They *must* include tariff provisions to implement all of the elements in new section 284.14, including unbundled sales, storage, and transportation service on an open access, nondiscriminatory basis, to achieve full equality of service, and to allocate capacity rights on the pipeline's facilities and on upstream pipelines to the pipeline's firm customers.[302] There must be tariff provisions specifying the operational conditions necessary to provide no-notice transportation service, maintain adequate pressure and reliable service at all times, and specifying

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301. However nothing here precludes early implementation if the pipeline and the parties agree otherwise.

302. Pipelines with storage facilities must provide detailed explanation and support for their proposed allocation of storage capacity among services.

procedures for operating under curtailment of gas supply or capacity. These filings must also include tariff provisions to implement a capacity release program in conformity to the requirements of this final rule.

The *pro forma* rates must reflect the currently approved cost of service and incorporate the straight fixed variable method of rate design unless the Commission approves otherwise. As discussed in Section VIII, *supra*, the filing must include a comparison of the revenue responsibility of each of the pipeline's historic customer classes under SFV and the pipeline's last approved cost classification method. If the revenue responsibility of any class increases 10 percent or more, the pipeline must also include a phase-in plan for implementation. The filing must include detailed explanations of the reasons for each of the pipeline's proposed rates, tariff provisions, and operational provisions, and must include the pipeline's estimate of the costs it expects to incur as a result of complying with this final rule, and any mechanisms proposed to recover those costs. Additionally, pursuant to the Notice of Proposed Policy Statement on Incentive Regulation (Docket No. PL92-1-000), issued March 13, 1992,[303] the Commission is receiving public comment on incentive ratemaking. In issuing the notice of proposed policy statement, the Commission recognized that the pipelines may want to utilize incentive ratemaking proposals as a competitive tool in the restructuring proceedings. Subject to the Commission's actions in the final policy statement on incentive regulation,[304] the pipelines may wish to file an

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303. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, 58 FERC ¶ 61,287 (1992).

304. The Commission expects to issue a final policy statement on (Cont'd)

incentive rate proposal along with its restructuring compliance filing. Any such incentive ratemaking proposal filed contemporaneously with the restructuring compliance filing should include sufficient detail to demonstrate the effect of the incentive rates on the straight fixed-variable (SFV) and unbundling objectives discussed above. Additionally, any incentive rate proposal must have the full support of the parties to the restructuring proceedings and be consistent with the Commission's final policy statement.

Some of the commenters assert that it may take some pipelines as much as two years to work out the operational details necessary to ensure reliable and efficient operation in an unbundled environment, without costly new facilities. The Commission disagrees and will not tolerate any unnecessary delay in compliance with this order. Pipelines will bear a heavy burden of persuasion for any request for additional time to postpone full implementation beyond what is necessary for implementation for the 1993-1994 winter heating season. In no event will the Commission permit pipelines to begin charging market-based rates for gas, to make unconstrained ISS sales, or to recover 100 percent of their transition costs, before the Commission determines (by acceptance of the compliance tariff sheets) that they have complied fully with this rule.

The Commission will issue orders on the restructuring filing, and establish further procedures if necessary in view of protests or other comments on the pipeline's filing. The Commission hopes that pipelines and interested parties will achieve a

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Incentive Ratemaking of Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities as soon as possible after the close of the period for public comment on April 27, 1992.

consensus on most features of the restructuring filing before it is filed. If the filing enjoys substantial support, no substantial opposition, and is in compliance with the requirements of this final rule, the Commission will permit the pipeline's proposal to be implemented on a prospective basis in short order.

The Commission will use procedures designed to achieve the most expeditious resolution of any contested issues raised with respect to the restructuring filings. If elements of the compliance filing are in patent conflict with the requirements of this final rule, or other applicable law or policy, the Commission may make summary dispositions on the merits. If review of a pipeline's compliance filing indicates that a pipeline will not achieve full compliance with this rule on a timely basis, the Commission may issue an interim compliance order, to provide direction to the pipeline on the steps necessary to correct deficiencies in its proposal soon enough to avoid delay in implementation of this rule. If there is substantial opposition to the pipeline's plan, but indications that further settlement discussions may resolve the points in dispute expeditiously, the Commission may direct the staff to convene settlement conferences and establish a deadline for submission of a report on the status of the settlement discussions. In proceedings where there are disputed issues that require development of a record, but not necessarily by means of a trial-type hearing, the Commission may use expedited "paper hearing" procedures. The Commission does not intend to require development of a record in a trial-type hearing; therefore the restructuring proceedings will not be set for hearing before administrative law judges unless they are consolidated with other proceedings already pending before a judge.

In several recent cases, the Commission has reviewed

"contesting party provisions" in settlement proposals that appeared to coerce parties into waiving their statutory rehearing and appeal rights by denying them certain services if they seek rehearing or judicial review of an order accepting the settlement.[305] These cases raise the specter that pipelines in restructuring proceedings under the final rule will seek to incorporate such provisions into unilateral settlement offers. The Commission is encouraging the development of settlements to implement this rule. However, as a matter of public policy, the Commission will not tolerate coercive provisions included in a pipeline's offer of settlement that have the effect of forcing parties to acquiesce in a settlement, or parts of a settlement, by threatening the denial of essential services.[306] Thus, a pipeline cannot deny access to its open access storage services, unbundled firm and interruptible transportation services, no-notice delivery service, or capacity release program to a party that contests some provision of its settlement proposal in a restructuring proceeding. The Commission will resolve the issues in contested settlements on the merits, and avoid any question of contesting parties being denied essential services while litigating the contested issues.

To a large extent, the date by which each pipeline fully implements the restructuring required by this rule will depend on the diligence and good faith of the pipeline and interested parties. The Commission has established deadlines for filings and has provided direction for making those filings. The Commission will continue to provide direction and guidance for fully implementing the policies reflected by the requirements of this rule. The Commission respects the rights of pipelines

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305. *See* Tennessee Gas Pipeline Co., 57 FERC ¶ 61,360 (1991); and CNG Transmission Corp, 55 FERC ¶ 61,189 (1991).

306. *See* CNG Transmission Corp., 55 FERC at p. 61,643.

and interested parties to differ over how these policies should best be implemented on a particular pipeline system. However, the Commission will not abide recalcitrance in the restructuring proceedings. If the pipeline's filings are not in compliance with the requirements of this rule, and the pipeline and interested parties cannot resolve differences over what is required to bring the pipeline into full compliance, the Commission will resolve the disputes on the merits. And once the Commission has determined how this rule must be implemented on a particular pipeline system, it will bring the full panoply of its enforcement resources to bear to ensure compliance with its decision.

3. Other Matters

A number of pipelines have urged the Commission to exempt them from the final rule because, they allege, their unique circumstances make applicability of the rule inappropriate. Northern Border Pipeline Company, Overthrust Pipeline Company, Ozark Gas Transmission System, Trailblazer Pipeline Company, and Wyoming Interstate Company argue that the Commission must recognize their unique status as project-financed pipelines and allow flexibility with regard to compliance with the rule. These pipelines state that the provisions regarding capacity reallocation may create problems for them because their lenders have relied on the credit standing of their firm transportation customers as collateral. They assert that assigning capacity to other shippers may necessitate restructuring of their credit agreements or may put them in default. Northern Border also argues that it should be allowed to continue to use its cost-of-service rate design because it is similar in concept to SFV and is appropriate for a transportation only pipeline. Several of these pipelines cite *Ozark Gas*

Transmission System v. FERC,[307] as holding that the Commission cannot approve a project-financed pipeline, and then later impose conditions that jeopardize its financing.

The capacity releasing program adopted by the final rule will not jeopardize the financing arrangements of these pipelines. As explained above, unless the pipeline otherwise agrees, the firm transportation customer releasing capacity will remain liable on its contract with the pipeline but will receive a credit against its bill on the capacity resold. Thus, the customers whose credit standing has been relied upon by the lenders remain the same. The appropriate rate design for project financed pipelines may be addressed in the individual restructuring proceedings.

Freeport Interstate Pipeline, Pacific Interstate Offshore Co., Pacific Offshore Pipeline Co., and Superior Offshore Pipeline Company and Texas Sea Rim Pipeline, Inc. argue that compliance with the rule is not necessary or appropriate for them because they are small, special purpose, Outer Continental Shelf (OCS) pipelines, generally serving only one customer. Similarly, Alabama-Tennessee Natural Gas Company and Gas Transport, Inc. argue that they should be exempt from the final rule because they are small, non-major pipelines. Gas Transport asserts that administrative costs and burdens will be disproportionately large for small pipelines.

These non-major and OCS pipelines may be required to make few, if any, changes to bring their operations into compliance with the rule, particularly if they provide transportation service only. However, the Commission will not adopt a general exemption for all OCS and non-major pipelines.

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307. 897 F.2d 548 (D.C. Cir. 1990).

Instead, the Commission will direct these pipelines to file in a restructuring proceeding and the Commission will address the appropriate requirements for each pipeline in those proceedings.

Great Lakes Transmission Limited Partnership states that the release of upstream capacity is impossible for pipelines transporting Canadian gas from the International Boundary. Great Lakes asserts that much of this gas is subject to regulation by both Canadian and U.S. authorities and that some of the provisions of the rule may be inconsistent with Canadian gas regulation. Great Lakes argues that the rule must be amended to recognize that independent multi-national transportation agreements exist which are subject to international regulation.

Section 284.282 of the final rule provides that downstream pipelines must allocate their capacity on upstream pipelines to firm customers, if the upstream pipeline provides transportation under Subpart B or G of Part 284 of the Commission's regulations. Any problems that arise in the implementation of this rule because of the character or nature of certain pipeline transactions will be addressed on a case-by-case basis in the restructuring proceedings.

XII. ENVIRONMENTAL ANALYSIS

The Commission concludes that the final rule does not represent a major federal action having a significant adverse impact on the human environment under the Commission's regulations implementing the National Environmental Policy Act.[308] The final rule falls within the categorical exemption provided in the Commission's regulations for the review of rates

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308. 18 CFR Part 380.

for the transportation and sale of natural gas under sections 4 and 5 of the NGA[309] and for the sale, exchange, and transportation of natural gas under sections 4, 5, and 7 of the NGA[310] that require no construction of facilities. If construction is proposed in the future, it will be evaluated in individual proceedings. Consequently, neither an environmental assessment or an environmental impact statement is required.

In comments on the NOPR, the Panhandle Customer Group objects to this finding because, they allege, the rule effectively requires LDCs to construct storage and transmission facilities and would encourage producers and marketers to construct new gathering facilities. The Panhandle Customer Group argues that the Commission must consider alternatives to the proposed rule that would result in less construction activity.

The assertions of the Panhandle Customers are entirely unsubstantiated. Nothing in the rule directs or authorizes construction of any facilities. Impacts of future construction will be evaluated by the Commission or by the appropriate environmental authority if a specific proposal is presented.

XIII. REGULATORY FLEXIBILITY CERTIFICATION

The Regulatory Flexibility Act (RFA)[311] generally requires a description and analysis of rules that will have a significant economic impact on a substantial number of small entities.

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309. 18 CFR 380.4(a)(25).

310. 18 CFR 380.4(a)(27).

311. 5 U.S.C. 601-612 (1988).

Pursuant to section 605(b) of the RFA, the Commission certifies that the final rule will not have a significant impact on a substantial number of small entities.

In comments on the NOPR, the Panhandle Customer Group objects to this finding, alleging that the rule will have a severe economic impact on small LDCs that serve largely residential loads. They assert that elimination of unscheduled delivery service will require expenditures for electronic metering and computing equipment, and that adoption of the SFV rate design and the capacity releasing program will have an economic impact.

Again, these allegations are unsubstantiated.[312] The Commission has explained above why the rule will not have an adverse economic impact on any LDC, large or small.

XIV. INFORMATION COLLECTION

The Office of Management and Budget's (OMB) regulations require that OMB approve certain information collection requirements imposed by agency rules.[313]

In the NOPR, the Commission estimated the public reporting burden for the collection of information in the proposed rule to average 4,810 hours per response under FERC-544, Gas Pipeline Rates: Rate Change (Formal) (1902-0153). The total reporting burden associated with the proposed rule was estimated to be 408,850 hours. The estimate included time for reviewing

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312. In any event, the rule does not eliminate no-notice service.

313. 5 CFR Part 1320.

the requirements adopted in the rule, searching existing data sources, gathering and maintaining the data needed, completing and reviewing the collection of information and filing this information with the Commission. In the NOPR, the Commission stated that interested persons could file comments regarding this burden or other aspects of this collection of information, including suggestions for reducing this burden, to the Commission. No comments were received on the public reporting burden. The final rule establishes certain requirements and information collections that differ slightly from the NOPR.

The information collection forms affected by the final rule are: FERC-545, Gas Pipeline Rates: Rate Change (Non-formal), (1902-0154); FERC-549, Gas Pipeline Rates: NGPA Title III Transactions; Ceiling Prices; Old Gas Pricing Structure, (1902-0086); and FERC-592, Marketing Affiliates of Interstate Pipelines (1902-0157). These information collections are required in order for the Commission to carry out its legislative mandate under the NGA and the NGPA. The information required by the final rule will allow the Commission to ensure that firm transportation service provided under Part 284 of the Commission's regulations for nonpipeline sellers is equal to transportation service associated with a pipeline's firm sales service.

An estimated 89 respondents will be affected by this rule. The respondents will consist of pipeline companies subject to the Commission's jurisdiction that perform self-implementing transportation under either the NGA or the NGPA. The Commission finds that: (a) the public reporting burden will average 4,810 hours per response under FERC-545, 2.7 hours per response under FERC-549, and 9.94 hours per response under FERC-592. The annual reporting burden will be 428,090

hours for FERC-545, 410 hours for FERC-549, and 885.2 hours for FERC-592, for a total estimated burden of 429,385.2 hours; (b) the frequency of response under FERC-545 will be a one-time filing by respondents; (c) for the other data collections the number of annual responses will vary. The Commission anticipates that the public reporting burden will decrease substantially after the one-time implementation filings have been made.

XV. EFFECTIVE DATE

This Final Rule is effective [insert date 30 days after publication in the *Federal Register*].

List of subjects in 18 CFR Part 284

Continental shelf
Natural gas
Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission amends Part 284, Chapter I, Title 18, *Code of Federal Regulations,* as set forth below.

By the Commission. Commissioner Langdon concurred in part and dissented in part with a separate statement attached.

(SEAL) Commissioner Terzic concurred with a separate statement to be issued later.

Lois D. Cashell,
Secretary.

Appendix B

PART 284 — CERTAIN SALES ANDTRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

1. The authority citation for Part 284 continues to read as follows:

Authority: 15 U.S.C. 717-717w; 15 U.S.C. 3301-3432; 43 U.S.C. 1331-1356; 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR, 1978 Comp., p. 142.

2. In § 284.1, paragraph (a) is revised and a new paragraph (c) is added to read as follows:

§ 284.1 ***Definitions.***

(a) *Transportation* includes storage, exchange, backhaul, displacement, or other methods of transportation.

* * * * *

(c) *Market center* means an area where gas purchases and sales occur at the intersection of different pipelines.

3. In § 284.8, paragraph (a)(1) is revised, new paragraph (a)(4) is added, paragraph (b) is revised by adding paragraph (b)(1) designation after the heading, "*Non-discriminatory access.*" and before the words "An interstate pipeline", paragraphs (b)(2) through (b)(5) are added, and paragraph (d) is revised to read as follows:

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§ 284.8 *Firm transportation service.*

(a) *Firm transportation availability.* (1) An interstate pipeline that provides transportation service under Subpart B or G of this part must offer such transportation service on a firm basis and separately from any sales service.

* * * * *

(4) An interstate pipeline that provided a firm sales service on [insert date 30 days after publication in the *Federal Register*], and that offers transportation service on a firm basis under Subpart B or G of this part, must offer a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty.

(b) *Non-discriminatory access.* (1) * * *

(2) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must provide each service on a basis that is equal in quality for all gas supplies transported under that service, whether purchased from the pipeline or another seller.

(3) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must provide all shippers with equal and timely access to information relevant to the availability of such service, including, but not limited to, the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, and whether the capacity is available directly from the pipeline or through capacity release.

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(4) The requirement of paragraph (b)(3) of this section must be implemented through the use of an Electronic Bulletin Board on which the pipeline must provide for:

(i) Downloading by users,

(ii) Daily back-up of information displayed on the board, which must be available for user review for at least three years,

(iii) Purging information on completed transactions from current files,

(iv) Display of most recent entries ahead of information posted earlier, and

(v) On-line help, a search function that permits users to locate all information concerning a specific transaction, and a menu that permits users to separately access notices of available capacity, each record in the transportation log, and standards of conduct information.

(5) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part may not include in its tariff any provision that inhibits the development of market centers.

* * * * *

(d) *Reservation fee.* Where the customer purchases firm service, a pipeline may impose a reservation fee or charge on a shipper as a condition for providing such service. Except for pipelines subject to Subpart C of this part, if a reservation fee is charged, it must recover all fixed costs attributable to the firm

transportation service, unless the Commission permits the pipeline to recover some of the fixed costs in the volumetric portion of a two-part rate. A reservation fee may not recover any variable costs or fixed costs not attributable to the firm transportation service. Except as provided in this paragraph, the pipeline may not include in a rate for any transportation provided under Subpart B, C or G of this part any minimum bill or minimum take provision, or any other provision that has the effect of guaranteeing revenue.

* * * * *

4. In § 284.9, paragraph (a)(1) is revised, paragraph (b) is revised by adding paragraph (b)(1) designation after the heading, "*Non-discriminatory access.*" and before the words "An interstate or intrastate pipeline", and new paragraphs (b)(2) through (b)(5) are added to read as follows:

§ 284.9 ***Interruptible transportation service.***

(a) *Interruptible transportation availability.* (1) An interstate pipeline that provides firm transportation service under Subpart B or G of this part must also offer transportation service on an interruptible basis under that subpart or subparts and separately from any sales service.

* * * * *

(b) *Non-discriminatory access.*

(1) * * *

(2) An interstate pipeline that offers transportation service

on an interruptible basis under Subpart B or G of this part must provide each service on a basis that is equal in quality for all gas supplies transported under that service, whether purchased from the pipeline or another seller.

(3) An interstate pipeline that offers transportation service on an interruptible basis under Subpart B or G of this part must provide all shippers with equal and timely access to information relevant to the availability of such service.

(4) The requirement of paragraph (b)(3) of this section must be implemented through the use of an Electronic Bulletin Board with the features required under § 284.8(b)(4).

(5) An interstate pipeline that offers transportation service on an interruptible basis under Subpart B or G of this part may not include in its tariff any provision that inhibits the development of market centers.

* * * * *

5. Section 284.12 is revised by removing the words "May 1" and adding, in their place, the words "March 1", and by inserting the phrase ",and the estimated storage capacity and maximum daily delivery capability of storage facilities," after "pipeline's system" and before "under".

6. Section 284.14 is added to read as follows:

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§ 284.14 ***Provisions governing pipeline restructuring.***

(a) *Applicability.*

This section applies to any interstate natural gas pipeline that offers transportation service under Subpart B or G of this part on [insert date 30 days after publication in the *Federal Register*].

(b) *Compliance filing.* (1) The pipelines subject to this section must make a compliance filing on or before the dates set forth in paragraph (b)(4) of this section to implement the provisions of § 284.1(a), § 284.8(a)(1), (a)(4), (b)(2)-(5), and (d), § 284.9(a)(1) and (b)(2)-(5), § 284.221(d), and Subparts H and J of this part, including, but not limited to, tariff provisions to implement without undue discrimination:

(i) Unbundled sales and transportation services,

(ii) Open access storage service,

(iii) Reasonable and non-discriminatory terms and conditions for operating unbundled open-access transportation,

(iv) Equality of transportation service for all gas transported under each rate schedule,

(v) Allocation of aggregate receipt point capacity, individual receipt point capacity, mainline segment capacity, storage capacity, and delivery point capacity,

(vi) Shipper flexibility in changing receipt and delivery points,

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(vii) Scheduling of gas injections into the mainline and into storage, scheduling of gas deliveries from storage and from the mainline, the setting and charging of penalties, balancing rights, and the instantaneous receipt and delivery of gas,

(viii) No-notice transportation service, with separately identified cost components,

(ix) Equality of access to information on availability of service,

(x) Non-discriminatory plans for operating under curtailment of capacity and gas supply (if the pipeline sells gas),

(xi) Rate design and cost allocation changes,

(xii) A capacity release mechanism,

(xiii) Right-of-first-refusal procedures for use upon the expiration of long-term, firm transportation contracts, and

(xiv) Assignment of capacity rights on upstream pipelines to firm customers.

(2) The compliance filing must be filed no later than the date specified for each pipeline in paragraph (b)(4) of this section in the restructuring proceeding instituted by the Commission for the implementation of the provisions listed in paragraph (b)(1) of this section.

(3)(i) The changes in rates, charges, classifications, or services, or in any rule, regulation, or service agreement, necessary to comply with this paragraph must be filed as *pro*

forma tariff sheets, for illustrative purposes only, with rates that are designed to recover the same revenue requirement as the pipeline's rates in effect on the date the compliance filing is made.

(ii) The compliance filing must also include a comparison of the revenue responsibility of each of the pipeline's historical customer classes for the unbundled services under

(A) the pipeline's last approved cost classification method for cost allocation and rate design, and

(B) the straight fixed-variable (SFV) cost classification method for cost allocation and rate design.

Under the straight fixed-variable method all fixed costs are classified to the demand component. If the comparison shows that adopting SFV for cost allocation and rate design will result in a 10 percent or greater increase in revenue responsibility for any customer class, the compliance filing must include a plan for phasing-in the cost shift due to SFV over no more than a four year period.

(iii) The compliance filing must also include an estimate of the costs of implementing the provisions of this paragraph and any mechanisms proposed for recovering those costs.

(4) The following pipelines must file on or before October 1, 1992:

ANR Pipeline Company

ANR Storage Company

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Arkla Energy Resources

Colorado Interstate Gas Company

Columbia Gas Transmission Corporation

Columbia Gulf Transmission Corporation

Michigan Gas Storage

Northern Natural Gas Company

Questar Pipeline Company

Southern Natural Gas Company

Texas Eastern Transmission Corporation

Williams Natural Gas Company

Williston Basin Interstate Pipeline

The following pipelines must file on or before November 2, 1992:

CNG Transmission Corporation

Equitrans, Inc.

Florida Gas Transmission Company

Iroquois Gas Transmission

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Kentucky-West Virginia Gas Company

KN Energy, Inc.

Mid Louisiana Gas Company

National Fuel Gas Supply Corporation

Panhandle Eastern Pipe Line Company

Tennessee Gas Pipeline Company

Texas Gas Transmission Corporation

Trunkline Gas Company

United Gas Pipe Line Company

The following pipelines must file on or before December 1, 1992:

Alabama Tennessee Natural Gas Company

Algonquin Gas Transmission Company

Altamont Gas Transmission Company

Carnegie Natural Gas Company

Cornerstone Pipeline Company

Delta Pipeline Company

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East Tennessee Natural Gas Company

Gas Gathering Corporation

Gas Transport Inc.

Gateway Pipeline Company

Green Canyon Pipeline Company

Gulf States Transmission Corporation

Inland Gas Company, Inc.

Louisiana Nevada Transit Company

Midwestern Gas Transmission Company

MIGC, Inc.

Mississippi River Transmission Corporation

Moraine Pipeline Company

Natural Gas Pipeline Company of America

Pacific Gas Transmission Company

Phillips Gas Pipeline Company

Riverside Pipeline Company

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South Georgia Natural Gas Company

Valero Interstate Transmission Company

Valley Gas Transmission, Inc.

Viking Gas Transmission Company

Western Gas Interstate Company

Western Transmission Corporation

Wyoming California Pipeline

The following pipelines must file on or before December 31, 1992:

Black Marlin Pipeline Company

Canyon Creek Compression Company

Caprock Pipeline Company

Chandeleur Pipe Line Company

El Paso Natural Gas Company

Freeport Interstate Pipeline Company

Gasdel Pipeline System, Inc.

Great Lakes Gas Transmission

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High Island Offshore System

Kern River Gas Transmission Company

Mojave Pipeline Company

Northern Border Pipeline Company

North Penn Gas Company

Northwest Pipeline Corporation

OkTex Pipeline Company

Overthrust Pipeline Company

Ozark Gas Transmission System

Pacific Interstate Offshore Company

Pacific Offshore Pipeline Company

Paiute Pipeline Company

Pelican Interstate Gas System

Point Arguello Natural Gas Line Company

Sabine Pipe Line Company

Sea Robin Pipeline Company

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Seagull Interstate Corporation

Stingray Pipeline Company

Superior Offshore Pipeline Company

Tarpon Transmission Company

Texas Sea Rim Pipe Line, Inc.

Trailblazer Pipeline Company

Transcontinental Gas Pipe Line Corporation

Transwestern Pipeline Company

U-T Offshore System

West Gas Interstate, Inc.

Wyoming Interstate Company, Ltd.

(c) *Restructuring discussions.* (1) By June 8, 1992, a pipeline subject to this section must initiate restructuring discussions concerning implementation of the provisions of this section with all its customers and other interested parties that intervene in its restructuring proceeding instituted by the Commission for implementation of the provisions listed in paragraph (b)(1) of this section.

(2) By July 7, 1992, a pipeline subject to this section must prepare and serve a summary of its proposed restructuring plan on every intervenor in its restructuring proceeding, addressing

each and every element of the compliance filing required under paragraph (b)(1) of this section.

(d) *Adjustments to obligations to purchase gas; automatic abandonment of sales.* (1) Any firm sales customer of a pipeline subject to this section may reduce or terminate its right or obligation to purchase gas under any contract with that pipeline for the sale of natural gas in effect on [insert date 30 days after publication in the *Federal Register*] by giving notice to the pipeline during the pipeline's restructuring proceeding.

(2) A pipeline subject to this section is authorized to abandon the sale of gas to any purchaser to the extent (i) the purchaser exercises its right to reduce or terminate its right or obligation to purchase under the provisions of paragraph (d)(1) of this section, or (ii) the purchaser refuses to pay the rate the pipeline offers for unbundled gas sales. The pipeline must file a report of any such abandonment of sales with the Commission within 30 days of the date of abandonment.

(3) The reduction or termination of service under the contract and the abandonment of sales under paragraph (d)(2) of this section will be effective on the effective date (as approved by the Commission) of the tariff sheets implementing service under the pipeline's blanket certificate for unbundled sales services under § 284.284.

(e) *Adjustments to firm transportation service; automatic abandonment.* (1) Any firm shipper on a pipeline subject to this section must give notice to the pipeline during the pipeline's restructuring proceeding that the shipper wants to retain, reduce, or terminate its contractual rights to firm transportation service.

(2) Except as provided in paragraph (e)(4) of this section, a pipeline subject to this section may abandon firm transportation service under a contract with a firm shipper to the extent the shipper gives the notice to reduce or terminate described in paragraph (e)(1) of this section. The authority to abandon service does not apply unless during the pipeline's restructuring proceeding (i) the pipeline executes a contract with another shipper for the transportation rights, or (ii) the pipeline agrees to the reduction or termination of contractual rights.

(3) The authority to abandon service under this paragraph is effective respectively (i) on the effective date of the contract described in paragraph (e)(2) of this section or (ii) on the effective date of the pipeline's agreement to the reduction or termination of contractual rights described in paragraph (e)(2).

(4) Paragraph (e)(1) of this section does not apply to the firm transportation service provided for a downstream pipeline subject to Subpart B or G of this part on an upstream pipeline subject to Subpart B or G of this part.

7. In § 284.106, the introductory text of paragraph (a) is revised by inserting the words "(except storage)" after "transportation" and before "under § 284.102," the introductory text of paragraph (c) is revised by removing the words "May 1" and adding in their place, the words "March 1", and by inserting the words "(except storage)" after "transportation service" and before "provided," and the introductory text of paragraph (d) is revised by inserting the words "(except storage)" after "transportation arrangement" and before "under § 284.102".

8. In § 284.106, a new paragraph (g) is added, to read as follows:

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§ 284.106 ***Reporting requirements.***

* * * * *

(g) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline shall file with the Commission a report of storage activity provided under the authority of § 284.102. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(2) The rate schedule under which the storage injection or withdrawal service was performed;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period; and

(6) The related docket numbers in which the interstate pipeline reported storage related injection/withdrawal transportation services.

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9. In § 284.126, the introductory text of paragraph (a) is revised by inserting the words "(except storage)" after "transportation" and before "under this subpart," the introductory text of paragraph (c) is revised by removing the words "May 1" and adding, in their place, the words "March 1", and by inserting the words "(except storage)" after "transportation service" and before "provided," and the introductory text of paragraph (d) is revised by inserting the words "(except storage)" after "transportation arrangement" and before "authorized".

10. In § 284.126, a new paragraph (g) is added, to read as follows:

§ 284.126 ***Reporting requirements.***

* * * * *

(g) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the intrastate pipeline shall file with the Commission a report of storage activity provided under the authority of § 284.122. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage;

(2) The docket where the storage injection or withdrawal rates were approved;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer; and

(6) The related docket numbers in which the intrastate pipeline reported storage related injection/withdrawal transportation services.

11. In § 284.221, paragraph (d) is revised to read as follows:

§ 284.221 ***General rule; transportation by interstate pipelines on behalf of others.***

* * * * *

(d) *Pre-grant of abandonment.* (1) Except as provided in §§ 284.14(e), and paragraphs (d)(2) and (d)(3) of this section, abandonment of transportation services is authorized pursuant to Section 7(b) of the Natural Gas Act upon the expiration of the contractual term or upon termination of each individual transportation arrangement authorized under a certificate granted under this section.

(2) Paragraph (d)(1) of this section does not apply if the individual transportation arrangement is for firm transportation under a contract with a term of more than one year, and the firm shipper:

(i) Exercises any contractual right to continue such service; or

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the maximum rate under § 284.7, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching those terms.

(3) Paragraph (d)(1) of this section does not apply where, after February 13, 1991, and before [insert date 30 days after publication in the *Federal Register*], a shipper converted from sales service to firm transportation service under the provisions of § 284.10 or under a separate agreement (to the extent of conversion of pre-existing sales volumes).

* * * * *

12. In § 284.223, the introductory text of paragraph (d)(1) is revised by inserting the words "(except storage)" after "transportation" and before "authorized," the introductory text of paragraph (d)(3) is revised by removing the words "May 1" and adding, in their place, the words "March 1", and inserting the words "(except storage)" after "transportation service" before "provided," and the introductory text of paragraph (d)(4) revised by inserting the words "(except storage)" "transportation arrangement" and before "under this section".

13. In § 284.223, a new paragraph (d)(5) is added, to read as follows:

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§ 284.223 ***Transportation by interstate pipelines on behalf of shippers other than interstate pipelines.***

* * * * *

(d) *Reporting requirements.*

* * * * *

(5) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline shall file with the Commission a report of storage activity provided under the authority of this section. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(i) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(ii) The rate schedule under which the storage injection or withdrawal service was performed;

(iii) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(iv) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period;

(v) The unit charge and total revenues received during the

injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period; and

(vi) The related docket numbers in which the interstate pipeline reported storage related injection/withdrawal transportation services.

* * * * *

14. In Part 284, a new Subpart H is added to read as follows:

Subpart H — Assignment of Capacity on Interstate Pipelines

Sec.

284.241 ***Applicability.***

284.242 ***Assignment of firm capacity on upstream pipelines.***

284.243 ***Release of firm capacity on interstate pipelines.***

§ 284.241 ***Applicability.***

This Subpart applies to any interstate pipeline that offers transportation service under Subpart B or G of this part.

§ 284.242 ***Assignment of firm capacity on upstream pipelines.***

An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on upstream

pipelines that offer a transportation service under Subpart B or G of this part. An upstream pipeline is authorized and required to permit a downstream pipeline to assign its firm capacity to the downstream pipeline's firm shippers.

§ 284.243 ***Release of firm capacity on interstate pipelines.***

(a) An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must include in its tariff a mechanism for firm shippers to release firm capacity to the pipeline for resale by the pipeline on a firm basis under this section.

(b) Firm shippers must be permitted to release their capacity, in whole or in part, on a permanent or short-term basis, without restriction on the terms or conditions of the release. A firm shipper may arrange for a replacement shipper to obtain its released capacity from the pipeline. A replacement shipper is any shipper that obtains released capacity.

(c) A firm shipper that wants to release any or all of its firm capacity must notify the pipeline of the terms and conditions under which the shipper will release its capacity. The firm shipper must also notify the pipeline of any replacement shipper designated to obtain the released capacity under the terms and conditions specified by the firm shipper.

(d) The pipeline must provide notice of the release, the terms and conditions, and the name of any replacement shipper designated in paragraph (b) of this section, on an electronic bulletin board, for a reasonable period.

(e) The pipeline must allocate released capacity to the person offering the highest rate (not over the maximum rate)

and offering to meet any other terms and conditions of the release. If more than one person offers the highest rate and meets the terms and conditions of the release, the released capacity may be allocated on a basis provided in the pipeline's tariff, provided however, if the replacement shipper designated in paragraph (b) of this section offers the highest rate, the capacity must be allocated to the designated replacement shipper.

(f) Unless otherwise agreed by the pipeline, the contract of the shipper releasing capacity will remain in full force and effect, with the net proceeds from any resale to a replacement shipper credited to the releasing shipper's reservation charge.

(g) To the extent necessary, a firm shipper on an interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part is granted a limited-jurisdiction blanket certificate of public convenience and necessity pursuant to Section 7 of the Natural Gas Act solely for the purpose of releasing firm capacity pursuant to this section.

15. In Part 284, a new Subpart J is added to read as follows:

Subpart J — Blanket Certificates Authorizing Certain Natural Gas Sales by Interstate Pipelines

Sec.

284.281 ***Applicability.***

284.282 ***Definitions.***

284.283 ***Point of unbundling.***

Appendix B

284.284 ***Blanket certificates for unbundled sales services.***

284.285 ***Pregrant of abandonment of unbundled sales services.***

284.286 ***Standards of conduct for unbundled sales service.***

284.287 ***Implementation and effective date.***

284.288 ***Reporting requirements.***

§ 284.281 ***Applicability.***

This subpart applies to any interstate pipeline that offers transportation service under Subpart B or G of this part.

§ 284.282 ***Definitions.***

(a) *Bundled sales service* is gas sales service that is not sold separately from transportation service.

(b) *Sales service* includes firmor interruptible gas sales.

(c) *Unbundled sales service* is gas sales service that is sold separately from transportation service.

§ 284.283 ***Point of unbundling.***

A sales service is unbundled when gas is sold at a point before it enters a mainline system, at an entry point to a mainline system from a production area, or at an intersection with another pipeline system.

Appendix B

§ 284.284 ***Blanket certificates for unbundled sales services.***

(a) *Authorization.* An interstate pipeline that offers transportation service under Subpart B or G of this part is granted a blanket certificate of public convenience and necessity pursuant to Section 7 of the Natural Gas Act authorizing it to provide unbundled firm or interruptible sales in accordance with the provisions of this section.

(b) *Conversion to unbundled firm sales service and firm transportation service.* On the effective date of the pipeline's blanket certificate for unbundled sales services under paragraph (a) of this section, firm sales entitlements under any firm sales service agreement for a bundled sales service are converted to an equivalent amount of unbundled firm sales service and an equivalent amount of unbundled firm transportation service, except as adjusted in §§ 284.14(d) and (e).

(c) *Conversion to unbundled interruptible sales service and interruptible transportation service.* On the effective date of the pipeline's blanket certificate for unbundled sales services under paragraph (a) of this section, interruptible sales volumes under any interruptible sales service agreement for a bundled sales service are converted to an equivalent amount of unbundled sales service and an equivalent amount of unbundled interruptible transportation service.

(d) A pipeline that provides unbundled sales service under this section may serve as an agent of the sales customer to arrange for any pipeline-provided service necessary to deliver gas to the customer.

Appendix B

§ 284.285 ***Pregrant of abandonment of unbundled sales services.***

Abandonment of unbundled sales services is authorized pursuant to Section 7(b) of the Natural Gas Act upon the expiration of the contractual term or upon termination of each individual sales arrangement authorized under § 284.284.

§ 284.286 ***Standards of conduct for unbundled sales service.***

(a) To the maximum extent practicable, the pipeline must organize its unbundled sales and transportation operating employees so that they function independently of each other.

(b) The pipeline must conduct its business to conform to the requirements set forth in § 284.8(b)(2) and § 284.9(b)(2) with respect to the equality of service by not giving shippers of gas sold by the pipeline any preference over shippers of gas sold by any other merchant in matters relating to Part 284 transportation.

(c) The pipeline must comply with § 161.3(a), (b), (d) and (l) of this chapter and comply with § 161.3(c), (e), (f), (g), (h), and (i) of this chapter by considering its unbundled sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate.

(d) The pipeline must comply with § 250.16 of this chapter by considering its unbundled sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate.

(e) A pipeline that provides unbundled sales service under § 284.284 must file tariff provisions and procedures as part of its compliance filing under § 284.14 indicating how the pipeline

is complying with the standards of this section.

§ 284.287 ***Implementation and effective date.***

(a) Except as provided in paragraph (b) of this section, a pipeline that offers transportation under Subpart B or G of this part must file revised tariff sheets to implement the requirements of this Subpart J as part of the compliance filing required under § 284.14.

(b) A pipeline that offers transportation under Subpart B or G of this part that is not authorized to make sales for resale as of the date of its required filing under § 284.14 need not file to implement this Subpart J with its filing under § 284.14, but prior to offering any sales service, such a pipeline must file revised tariff sheets to implement this Subpart J.

(c) A blanket certificate issued under § 284.284 will be effective on the effective date (as approved by the Commission) of the tariff sheets implementing service under that certificate. For a pipeline that is required to file under § 284.14, the tariff sheets implementing service under the blanket certificate will not be effective until after Commission approval of the compliance filings required by § 284.14(b).

§ 284.288 ***Reporting requirements.***

Interstate pipelines engaging in sales under a certificate granted under § 284.284 must file with the Commission by March 1 of each year, an annual report for the preceding calendar year describing for each transaction the identities of the parties, the type of service provided (firm or interruptible), the total volumes sold, and the total revenues received. The report must be signed under oath by a senior official of the company.

Appendix B

Docket No. RM91-11-000

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-065

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued April 8, 1992)

JERRY J. LANGDON, Commissioner, *concurring in part and dissenting in part:*

This Order represents a watershed for the natural gas industry. It marks a turning point for parties to permanently leave outmoded and failed governmental policies behind to face a largely market-driven regulatory regime. Those who fail to take advantage of this opportunity to craft market-sensitive solutions to their energy needs will undoubtedly be left behind. This Order provides a road map to guide all parties toward a competitive market for natural gas without mandating which route they should choose.

I fully support this Order as a final major move toward realizing the promises first set forth in Order No. 436. In the past few years, the Commission has been criticized for its piecemeal approach to implementing important policy objectives. This piecemeal approach has unnecessarily prolonged the transition of the industry by limiting or obviating competitive choices by individual segments of the industry. By

dealing globally with a number of inter-related issues, the Commission will allow market forces — and not regulators — to begin to drive the natural gas industry.

I only regret that we did not take two more steps to facilitate the process:

- provide an additional mechanism to shorten the transition cost recovery process to allow true market signals to emerge sooner rather than later, and

- devise an alternative cost recovery mechanism for the non-market sensitive Great Plains gas.

As to the former I concur; as to the latter, I dissent as discussed below.

Order No. 636 provides only two mechanisms which act to limit gas supply realignment costs which may result from restructuring negotiations: eligibility and prudence. I take seriously the Order No. 636 process for both mechanisms in light of the billions of dollars that have already been billed to consumers in take-or-pay costs.

The Commission's past record on prudence review has been impotent at best. But, as a result of the full pass-through of transition costs allowed by this rule, the Commission has a new, larger prudence role to play. First, we must ensure that transition costs recovered pursuant to Order No. 636 are closely limited to contract realignments occurring as a direct result of implementing this rule. Second, we must determine that the remaining supply contracts are the product of prudent market-driven transactions.

Appendix B

In discussions leading up to the Final Order, I strongly favored an additional, *optional* mechanism which would have encouraged pipelines to offer 10 percent absorption of gas supply realignment costs in exchange for their customers' forgoing their rights to challenge prudence. I believe this optional approach is reasonable, and moreover, is not precluded by the rule. I expect that the pipelines and parties may well use this mechanism as an alternative to lengthy, costly and uncertain prudence reviews.

As to the Order No. 636 treatment of Great Plains gas, every comma, word, sentence and paragraph of the Order is internally inconsistent. Order No. 636's sweeping changes are driven by the overriding need to make natural gas a competitive commodity. We do this by eliminating cross-subsidies and by billing away costs associated with the old way of doing business. Yet in Great Plains, we are timid. I fail to see how the pass-through of such extraordinary gas costs will ultimately benefit the consumer, or transmit accurate pricing signals.

I understand the public trust responsibility with respect to recoupment of the public investment in Great Plains and I would support a proposal to retire that investment through a surcharge on natural gas transportation. The continued operational feasibility of Great Plains, however, should be a choice consumers should make by their willingness to pay the cost of converting coal to gas.

In all other regards, I enthusiastically support the Order. I expect that it will significantly contribute to improving the health and efficiencies of the natural gas industry to the benefit of the nation's consumers.

Jerry J. Langdon
Commissioner

Supreme Court, U.S.
FILED

No. 96 1186 JAN 27 1997

In The OFFICE OF THE CLERK

Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,

Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

AND RELATED PETITIONS

Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martin L. Allday, Chairman; Charles A Trabandt, Elizabeth Anne Moler, Jerry J. Langdon and Branko Terzic.

Docket No. RM91-11-002

PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS

Docket No. RM87-34-068

REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL

ORDER NO. 636-A

ORDER DENYING REHEARING IN PART, GRANTING REHEARING IN PART, AND CLARIFYING ORDER NO. 636

(Issued August 3, 1992)

Appendix C

I. INTRODUCTION

On April 8, 1992, the Federal Energy Regulatory Commission issued Order No. 636.[1] It requires significant structural changes in the services provided by natural gas pipelines. As discussed below, this order largely denies rehearing,[2] but grants rehearing in part to make a number of adjustments to Order No. 636 and clarifies Order No. 636.

II. SUMMARY OF ORDER NO. 636 AND MAIN CHANGES IN THIS ORDER

In Order No. 636, the Commission set forth in detail its goals in, and reasons for, restructuring the regulation of interstate natural gas pipeline services. In brief, the Commission found that the pre-Order No. 636 regulatory structure of the pipeline industry has, and will continue to have, a harmful impact on all segments of the natural gas industry and on the Nation. The Commission concluded that it was appropriate to take remedial action to improve the competitive structure of the natural gas industry to further the creation of an efficient national wellhead market for gas without adversely affecting the quality and reliability of the service provided by pipelines to their customers. The Commission believes that its action will result in a modern, viable natural gas industry specifically fashioned to the needs

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1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (April 16, 1992), III FERC Stats & Regs. ¶ 30,939 (1992).

2. See the appendix for a list of the parties seeking rehearing or clarification or both.

of all gas consumers and the Nation for an adequate and reliable supply of clean and abundant natural gas at reasonable prices.

In brief, the salient aspects of Order No. 636 are as follows:

- Pipelines must unbundle (*i.e.*, separate) their sales and transportation services.

- Pipelines must provide access to storage on an open access contract basis.

- Pipelines must provide open access transportation services that are equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere.

- Pipelines that provided a firm sales service on May 18, 1992, must offer a no-notice firm transportation service under which firm shippers may receive delivery of gas on demand up to their firm entitlements without incurring daily balancing and scheduling penalties.

- Pipelines must provide all shippers with equal and timely access to information relevant to the availability of their open access transportation services. The information must be provided through the use of an electronic bulletin board.

- Pipelines may not include in their tariffs any provision that inhibits the development of market centers.

Appendix C

- Open access pipelines must allow firm transportation customers of downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines.

- Pipelines must implement a capacity releasing program so that firm shippers can release unwanted capacity to those desiring capacity.

- Pipeline transportation rates must be developed under the Straight Fixed Variable (SFV) method of cost classification, allocation, and rate design unless the Commission permits the pipeline to use some other method; however, measures to mitigate cost shifts are required if the use of SFV will result in a 10 percent or greater increase in revenue responsibility for any historic customer class.

- Pipelines are granted blanket certificates for unbundled sales services and are subject to standards of conduct in connection with those services similar to those applicable to affiliate sales.[3] The

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3. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec.22, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. & (Cont'd)

unbundled sale services are subject to pregranted abandonment.

° Existing bundled firm sales entitlements are converted to unbundled firm sales entitlements and to unbundled firm transportation rights on the effective date of the particular pipeline's blanket sales certificate. However, effective on that date, pipeline firm sales customers may reduce, in whole or in part, their firm sales entitlements. Pipeline customers may not reduce their firm transportation rights unless the pipeline executes a contract with another shipper for the transportation rights or agrees to the reduction or termination of the contractual rights.

In addition, in Order No. 636, the Commission (1) amended Section 284.221(d) of the Commission's regulations in further response to the remand of the United States Court of Appeals for the District of Columbia Circuit in *American Gas Association v. FERC*,[4] (2) concluded that pipelines should be able to recover 100 percent of their prudently incurred costs attributable to the transition required by Order No. 636, and (3) adopted measures governing the implementation of Order No. 636.

(Cont'd)

Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. & Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992), *aff'd in part and remanded in part*, Tenneco Gas v. FERC, No. 89-1768 (D.C. Cir. July 21, 1992).

4. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S.Ct. 957 (1991).

Appendix C

The Commission is largely upholding the regulations adopted in and requirements of Order No. 636 except for a number of changes in response to the petitions for rehearing. Among other things, as discussed below, the Commission is granting rehearing as follows. First, the Commission is requiring pipelines to maintain their one-part volumetric rates computed at an imputed load factor to determine the transportation rates for "small customers" (as discussed below) and is requiring pipelines, for a one-year period (from the effective date of the blanket sales certificate granted by Order No. 636), to sell gas to the small customers that elect to continue buying gas from the pipeline at a cost-based rate (based upon their actual price paid for gas). Second, the Commission is allowing, subject to certain restrictions, capacity releases for any period of less than one calendar month without prior posting on the electronic bulletin board or bidding for the released capacity. Third, while the Commission is requiring SFV for rate design (billing) and cost allocation purposes, it will allow the parties in the restructuring proceedings to consider the use of other ratemaking techniques to distribute revenue responsibility among customers, such as through the use of seasonal contract quantities or entitlements, if these ratemaking techniques help address significant cost shifts which might result from an allocation based only on peak day entitlements under SFV. Last, the Commission is requiring pipelines to recover 10 percent of their gas supply realignment costs from their Part 284 interruptible transportation service.[5] The explanation and

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5. As discussed below, the Commission encourages the pipeline and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as appropriate true-up mechanisms, that provide a reasonable opportunity for pipelines to recover (but not overrecover) those costs.

rationale for these adjustments are set forth below in the relevant sections.[6]

III. LEGAL BASIS AND RATIONALE FOR UNBUNDLING

This part III addresses the rehearing requests with respect to the Commission's legal basis and rationale for adopting Order No. 636.

A. The Legal Basis

The Commission, in Order No. 636, concluded that the pipelines' bundled, city-gate, firm sales service contravenes Natural Gas Act (NGA) sections 4(b) and 5. The Commission, therefore, as required, determined the remedial action necessary to remedy the violations of the statutory standards.[7] This remedy consisted, among other things, of altering existing bundled sales contracts into two separate contracts for unbundled sales and transportation.

Various rehearing petitioners argue that the Commission has acted beyond its statutory authority by revoking or modifying certificates of public convenience and necessity for bundled sales service, by mandating new services, and by unbundling direct sales. In addition, a few petitioners argue that the Commission has violated the Administrative Procedure Act (APA) and the U.S. Constitution.

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6. For ease of reference, the organization of this order continues to follow the organization of subjects used in Order No. 636.

7. Order No. 636, III FERC Stats. & Regs. Preambles ¶ 30,939 at p. 30,408-13.

Appendix C

1. Procedural Arguments

CNG Transmission Corporation (CNG) argues that Order No. 636 violates the Due Process Clause of the Constitution[8] and the procedural safeguards of the APA. [9] CNG asserts that those safeguards required the Commission to provide an opportunity for pipelines to comment on whether they can provide a reliable no-notice transportation service. ANR Pipeline Company (ANR) contends that Order No. 636 violated the APA because parties did not have the opportunity to show the lawfulness of their existing contracts. Southern Indiana Gas and Electric Company (Southern Indiana) also asserts the Commission did not provide due process to those affected by Order No. 636 because it failed to hold an evidentiary hearing, failed to follow the requirements of the NGA, exceeded its statutory authority and jurisdiction, and issued Order No. 636 without evidentiary support. Tenneco Gas (Tenneco) asserts that the Commission violated the notice and comment procedures of the APA by failing to properly address the comments made by the parties and failing to give notice of several aspects of the rule (*e.g.*, no-notice service).[10]

The Commission provided parties with an unprecedented input into the year-long development of the Notice of Proposed Rulemaking (NOPR), and thereafter, the final rule. There was more than an ample opportunity to comment on all aspects of

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8. U.S. CONST. amend. V.

9. 5 U.S.C. 553 (1988).

10. ANR argues, without specificity, that the Commission contravened the APA by relying in Order No. 636 upon material and conclusions that were not identified in the Notice of Proposed Rulemaking.

the rule, including no-notice transportation. First, the July 31, 1991 NOPR[11] was, among other things, the outcome of a public conference held on May 10, 1991, where participants in the natural gas industry discussed with the Commission the future role of interstate natural gas pipelines in the natural gas markets. Second, parties submitted initial comments and reply comments to the NOPR.

Some of those comments raised concern about the reliability of unbundled transportation service in meeting the needs of LDCs to serve their customers at peak. For example, in their initial and reply comments, many pipelines and LDCs maintained that unbundling would prevent pipelines from providing the reliable, firm, city gate service, *i.e.*, no-notice service, that they provided in the past. Most producers and marketers, on the other hand, claimed that pipelines could replicate the bundled, firm, city gate service, *i.e.*, no-notice service, in an unbundled environment. In response, on December 27, 1991, the Commission gave notice of a technical conference to discuss operational aspects of the NOPR and specifically the ability of pipelines to provide an unbundled no-notice delivery service as a remedy to the reliability concerns raised in the comments. The December 27th Notice included several specific questions to which the public could respond concerning no-notice transportation service.[12] The Commission held the technical conference on January 22, 1992. There was a wide-ranging discussion between the participants and the Commission

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11. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 FR 38372 (Aug. 13, 1991), FERC Statutes and Regulations ¶ 32,480 (1991).

12. *See* 57 FR 385 (Jan. 6, 1992), III FERC Stats. & Regs. ¶ 35,022.

addressing various operational issues, including no-notice transportation service. In addition, parties were given the opportunity to file additional comments as a result of the technical conference. And while the issue of no-notice service may not have been designated as such at the beginning of this proceeding, the parties have focused specifically on operational issues and the need for a reliable no-notice service. Accordingly, the Commission in Order No. 636 required the no-notice transportation service as part of the mandatory unbundling remedy under NGA Section 5(a).[13]

The industry's comments therefore provided the Commission with a great deal of helpful information on what operational controls are required to provide no-notice transportation service in an unbundled environment. A representative of CNG, in particular, appeared at the technical conference and addressed the issue of why CNG needs to control storage hourly in order to provide no-notice service.[14] Furthermore, at the January 22, 1992 technical conference, the witnesses sponsored by the Interstate Natural Gas Association of America (INGAA), which included representatives of various pipelines, conceded that pipelines could provide no-notice transportation service if they retained certain operational controls over their systems. That all these parties commented on all aspects of no-notice service signifies that they had adequate notice of this issue.

The Commission has adequately addressed the comments of the parties. The Commission, in Order No. 636, outlined the

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13. See the more detailed discussion in Order No. 636 at pp. 30,406-30,409.

14. Technical Conference Tr. 73-77.

proposal in the NOPR on each issue, discussed the comments of the parties on the issue, and gave the reasons why it reached a particular outcome on each issue. The APA does not require an agency to respond to every fact or contention in the comments submitted, but only requires the agency to "respond[] to significant points raised by the public."[15]

Colorado Interstate Gas Company (CIG) argues that Order No. 636 did not comply with the APA's official notice requirements with respect to the data relied upon by Order No. 636. CIG maintains that it is entitled to a hearing to test the accuracy of the data relied upon by the Commission, and to determine whether the data permit a conclusion other than that drawn by the Commission.

CIG is incorrect in its assertion that the Commission failed to follow the requirements of the APA. CIG relies on 5 U.S.C. § 556, which does not apply to this proceeding.[16] This proceeding is a notice and comment rulemaking proceeding governed by 5

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15. *See* Home Box Office v. FCC, 567 F.2d 9, 35-36, (D.C Cir. 1977), *cert. denied*, 434 U.S. 829 (1977). (Footnote omitted).

16. Section 556(e), which was only *partially* quoted by CIG, states in full:

> The transcript of testimony and exhibits, together with all papers and requests filed in the proceeding, constitutes the exclusive record for decision in accordance with section 557 of this title and, on payment of lawfully prescribed costs, shall be made available to the parties. When an agency decision rests on official notice of a material fact not appearing in the evidence in the record, a party is entitled, on timely request, to an opportunity to show the contrary.

U.S.C. § 553. That section applies since the Commission is not required by statute to hold a hearing in order to promulgate a rule. Section 553 states:

> After notice required by this section, the agency shall give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments with or without opportunity for oral presentation. After consideration of the relevant matter presented, the agency shall incorporate in the rules adopted a concise general statement of their basis and purpose. When rules are required by statute to be made on the record after opportunity for an agency hearing, sections 556 and 557 of this title apply instead of this subsection.

Moreover, CIG has offered nothing to warrant the need to hold a hearing about the accuracy of the data used by the Commission in Order No. 636. Those data, garnered from INGAA, the Energy Information Administration (EIA), reports filed with the Commission, and other publicly available sources can be assumed to be accurate, especially since CIG has not offered anything to suggest the contrary. CIG merely asserts that the Commission erred by not holding a hearing. Hearings are held to establish disputed facts and are not needed to ventilate comparisons and conclusions.[17]

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17. *See* Cities Service Gas Company v. Federal Power Commission, 553 F.2d 1278, 1290 (D.C. Cir. 1976), where the court stated that it is a "settled rule that where there are no genuine, relevant, material, factual questions in dispute the [Commission] may proceed under sections 4 and 5 of the Natural Gas Act without formal evidentiary hearings." *See also* Mobil Oil Corp. v.

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Appendix C

2. Natural Gas Act Authority

CIG, Arkla, Inc. (Arkla), Tenneco, Cincinnati Gas & Electric Company, *et al.* (Cincinnati Gas),[18] and Natural Gas Pipeline Company of America (Natural), argue that the Commission exceeded its authority under NGA section 5 to modify or revoke a pipeline's certificate issued under NGA section 7. For example, Arkla states that NGA section 5 does not vest the Commission with the authority to cancel unilaterally a certificated service without the pipeline's consent. Similarly, Cincinnati Gas and Natural argue that this change is too fundamental to be viewed as anything but a certificate revocation. Tenneco maintains that the Commission may not revoke a certificate absent a violation of the certificate's conditions. Cincinnati Gas adds that the Commission consistently recognized the limitations of its NGA section 5 authority, and the need for action under NGA section 7 when there is a significant modification in the type or kind of service that a pipeline offers. Finally, Arkla contends that the Commission can satisfy NGA section 5 only by holding a hearing, collecting evidence, and making individualized findings.

As the Commission stated in Order No. 636, the Commission rejects contentions that its action under NGA

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Federal Energy Regulatory Commission, 886 F.2d 1023, 1033 (8th Cir. 1989), where the court stated "FERC is not required to hold evidentiary hearings where only questions of law and policy are matters in controversy[;]" and Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1168 n. 41 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986) (court rejected contentions that the "after a hearing" requirement found in NGA section 5 must be satisfied through a formal, trial-type hearing).

18. Cincinnati, Union Light, Heat and Power Company, Lawrenceburg Gas Company, and Mountaineer Gas Company filed a joint petition.

Section 5 violates NGA Section 7 because the Commission lacks the authority to revoke, suspend, or adversely modify an issued and accepted certificate.[19] To the contrary, the Commission's action is within its authority under NGA Section 5 to alter a pipeline's contractual terms and conditions of service to remedy an unlawful practice.[20]

The Commission adheres to its analysis and conclusion in Order No. 636 that its action under NGA section 5 is not an unlawful revocation or modification of a certificate of public convenience and necessity under NGA section 7. Section 7 cannot be read so narrowly as to permanently prevent the Commission from changing the terms and conditions under which a pipeline provides service, especially when the pipeline's obligation to serve and the LDC's entitlement under the certificate remain intact. Such a narrow reading of section 7 would prevent the Commission from making adjustments, contemplated by section 5, to the terms and conditions under which pipelines provide service when the Commission finds it necessary to satisfy the standards of the NGA in light of changing circumstances.

In this case, the regulations retain in an altered manner the LDC's entitlement to service and the pipeline's authorization and obligation to provide service.[21] An LDC and a pipeline are

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19. Order No. 636 at p. 30,422.

20. *Id.* at p. 30,423, *citing* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n.9 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986); Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 389 (1959); and Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 746 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988).

21. For example, a pipeline must provide no-notice transportation

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thus presented with two options. First, an LDC and a pipeline may agree upon the price for gas to be sold on an unbundled basis, while the firm transportation of gas to the city-gate under no-notice transportation service would continue to be priced under traditional ratemaking methods. Thus, their relationship would continue under the new terms and conditions of the pipeline's blanket transportation and blanket sales certificates. The pipeline's certificated obligations with respect to individual services are, in essence, merged into or subsumed within the pipelines' blanket certificates. Under the second option, if an LDC and a pipeline do not enter into an agreement pursuant to the procedures in Order No. 636, then and only then would the pipeline's *sales* service obligation cease as of the effective date of the tariff sheets filed in compliance with this rule. However, the pipeline must continue to provide transportation services to that customer, who, with the equality of transportation principles imposed here, is assured the ability to maintain reliable service.

Finally, Arkla's contention that the Commission can satisfy NGA section 5 only by holding a hearing, collecting evidence, and making individualized findings is without merit. In *Wisconsin Gas Co. v. FERC*,[22] the court specifically rejected contentions that the "after a hearing" requirement found in NGA section 5 must be satisfied through a formal, trial-type hearing.

The American Public Gas Association (APGA) contends that the Commission has violated NGA section 7(a) by abolishing

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service to customers receiving a no-notice, bundled, city-gate, firm sales service on the effective date of the rule.

22. 70 F.2d 1144, 1168 n. 41 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986).

bundled firm sales service.[23] It argues that the Commission has effectively repealed that section, which grants the Commission the authority to compel sales but not transportation services. Kentucky Ohio Gas Company (Kentucky Ohio) argues that the Commission must make clear that it will exercise its authority under NGA Section 7(a) to order pipeline interconnections with an LDC or municipality even when the LDC or municipality does not desire to purchase gas from the pipeline.

Pacific Gas Transmission Company (PGT), ANR, CNG, Tenneco and Arkla argue that the Commission is without authority to compel the pipelines to provide new services, such

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23. NGA Section 7(a) provides:

> Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural gas or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: *Provided*, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purpose, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

as open access storage, no-notice transportation, capacity releasing, and unbundled sales. For example, Arkla argues that NGA section 7 implicitly limits the Commission's ability to compel the provision of services. It argues that Congress would have had no reason to authorize the Commission to compel service under section 7(a), if the Commission could compel service under section 5(a). Arkla contends that the Commission's reliance on section 5(a) renders section 7(a) surplusage. Arkla also cites several Commission orders that required NGA section 7 action by pipelines to change service.[24] Similarly, CNG argues that the Commission has no authority under the NGA to order pipelines to provide new services that compel it to share assets (*e.g.* storage facilities).

Under NGA section 7(a), the Commission may order a pipeline to sell gas to a local distributor if the Commission finds it necessary or desirable in the public interest.[25] Contrary to the assertions of the petitioners, the Commission does not read section 7(a) as limiting the Commission's ability to act under section 5, as it has done in this proceeding. Section 7(a) establishes the standards the Commission must apply to require a pipeline to provide sales service to an LDC. The powers granted by Congress to the Commission in sections 7(a) and section 5 are separate and distinct, albeit complementary. Neither the purposes nor the terms of section 7(a) prevent the

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24. *E.g.*, Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,265 at p. 61,862 (1991) (changes in contract demand level); South Georgia Natural Gas Co., 48 FERC ¶ 61,383 at p. 62,539 (1989) (abandonment of standby service); Alabama Tennessee Natural Gas Co., 53 FERC ¶ 61,032 (1990) (service change from sales to sales-transportation).

25. *See* Rural Energy Systems, Inc., 34 FERC ¶ 61,389 at p. 61,723 n. 12 (1986).

Commission from assuring, once service to individual markets and territories has been established, that the protection against undue discrimination in service provided by sections 4, 5, and 7 of the NGA are available. First, section 7(a) applies only to new sales. It does not prevent the Commission from requiring changes in existing sales services. Second, the Commission is not compelling service in Order No. 636. The Commission is changing the terms of existing services and establishing through the procedures established by Order No. 636 the terms for future services. Even if the Commission is compelling the pipelines to provide "new" services to its open access transportation customers, it has the authority to do that in order to remedy undue discrimination.[26]

The Commission has exercised its authority under section 5 to find the pre-Order No. 636 regulatory structure, which includes the terms of existing services, unduly discriminatory and anticompetitive. The Commission has the authority under NGA section 5 to authorize the just and reasonable terms and conditions for the interstate transportation and sale for resale of natural gas. The requirements of Order No. 636 are all necessary to ensure that Part 284 transportation is performed on a just and reasonable, nondiscriminatory basis with respect to all gas supplies. Finally, the Commission's authority to compel sales service is discretionary. The Commission sees no reason, at this time, to determine whether at some future time it will compel a new sales service under section 7(a), and under what terms and conditions of service.

Arkla's argument that the Commission's reliance on section 5(a) renders section 7(a) surplusage is incorrect. The purpose

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26. Associated Gas Distributors v. FERC, 824 F.2d 981, 1000 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

of section 7(a) was to make it possible for communities that had no natural gas service to buy natural gas service from unwilling pipelines.[27] Thus, that section only authorizes the Commission to compel a pipeline to provide sales service (and to construct and operate facilities for that purpose). It relates to initiating a new sales arrangement rather than changing existing arrangements. How that section will or should be applied within the regulatory framework adopted in Order No. 636 is an issue the Commission leaves open for another day. Simply stated, section 7(a) does not prevent the Commission from prescribing reasonable terms and conditions of service under NGA section 5 as they relate to existing certificated service including sales and Part 284 transportation services.

The petitioners are incorrect in their assertion that the Commission lacks the authority to require pipelines to provide open access storage. First, the Commission has always regulated storage as part of its jurisdiction over interstate transportation.[28] Second, in Order No. 636, the Commission found the pipelines' bundled, city-gate, firm sales service to be unduly discriminatory under NGA sections 4(b) and 5(a). As part of the remedy the Commission concluded it was appropriate to regulate storage under Part 284 of the regulations. In Order No. 636, the Commission found that the pipelines' superior rights with respect to access and control of storage provide them with advantages

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27. *See* Rural Energy Systems, Inc., 34 FERC ¶ 61,389 at p. 61,722, *citing* Central Illinois Public Service Co. v. FPC, 338 F.2d 682, 687 (7th Cir. 1964).

28. *See* Texas Gas Transmission Corporation, 26 FERC ¶ 61,150 at p. 61,395 (1984) ("[W]e have viewed storage to be within the Commission's transportation jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978 (NGPA).").

over other gas merchants. The pipelines' ability to use storage for seasonal supply management, as a supplement to transmission capacity, and to maintain a constant flow of gas, give pipelines an unfair advantage over other gas merchants because they do not have the flexibility to provide fully a sales service which meets gas purchasers' peak needs. Access to storage is a key component of establishing equality of transportation, without it, pipelines' service will remain superior to other services that can be offered. Because the Commission is requiring the unbundling of pipeline sales and transportation services, pipelines with storage capacity downstream of the place it unbundles will need it only to fulfill their obligations with respect to system management (load balancing) and no-notice transportation service. Pipeline customers, of course, must have access to that storage to build their own gas supply portfolio and determine which services they need to replace pipeline bundled, city-gate, firm sales service. In addition, access to storage for pipeline customers such as LDCs will help them achieve a more efficient load profile between peak and offpeak seasons. For example, an LDC will be in a better position to buy, ship, and store gas in the summer for use in the winter instead of buying that gas from the pipeline in the winter.

The argument that the Commission is unlawfully requiring pipelines to provide new services that compel them to share assets (*e.g.* storage facilities) is without merit because the Commission is not compelling a new service. The no-notice transportation service will be similar to the transportation service imbedded in pipelines' current, bundled, firm sales service. Because, among other things, the Commission is unbundling the sale of gas from existing service by moving the point of sale as far upstream as possible, pipelines will not require the same amount of storage as they have in the past. However, the

Commission recognized that pipelines would require a certain amount of storage to provide no-notice transportation service and for load balancing purposes. After the amount of storage capacity needed by the pipeline is determined, the remaining storage capacity must be offered on an open access, nondiscriminatory basis because the Part 284 regulations will include storage within the definition of transportation. Further, it should make good business sense for a pipeline to allow shippers and other gas merchants to obtain the storage capacity that it no longer needs because it will be operating in an unbundled environment. Finally, the petitioners are also incorrect in their assertion that the Commission lacks the authority to require pipelines to provide no-notice transportation service. The Commission, pursuant to NGA section 5, found bundled, city-gate, firm sales service to be unduly discriminatory and preferential. As a remedy, the Commission determined that a just and reasonable practice would be the separate provision of no-notice transportation service embedded within the bundled sales service. The Commission found that this requirement was necessary so that a customer could receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices from other sellers. The Commission is separating existing service into two parts. As discussed above, it is not compelling a new service because it is just separating the sale of gas from the existing service.

3. Direct Sales

Arkla contends that the Commission lacks the authority to cancel or modify nonjurisdictional sales contracts under any

circumstances,[29] and therefore, Order No. 636 must be modified to exclude nonjurisdictional, direct sales contracts from mandatory unbundling.

In *Panhandle Eastern Pipe Line Co. v. Public Service Commission of Indiana*,[30] the Supreme Court discussed the Commission's jurisdiction under section 1(b) of the Natural Gas Act. The Court stated:

> Three things and three only Congress drew within its own regulatory power, delegated by the Act to its agent, the Federal Power Commission. These were: (1) the transportation of natural gas in interstate commerce; (2) its sale in interstate commerce for resale; and (3) natural gas companies engaged in such transportation or sale.[31]

In *FPC v. Louisiana Power and Light Co.*,[32] which concerned pipelines' curtailment plans, the Supreme Court further clarified the Commission's jurisdiction under section 1(b) of the Natural Gas Act. The court stated:

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29. *Citing* Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 500-H, FERC Stats. and Regs. ¶ 30,867 at 31,540 (1989), *aff'd*, American Gas Association v. FERC, 912 F.2d 1496, 1507 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (The Commission has no authority to abrogate nonjurisdictional producer/pipeline contracts.)

30. 332 U.S. 507 (1947).

31. *Id.* at 516.

32. 406 U.S. 621 (1971).

> [T]he prohibition of the proviso of § 1(b) withheld from FPC only *rate-setting* authority with respect to direct sales. Curtailment regulations are not *rate-setting* regulations but regulations of the "transportation" of natural gas and thus within FPC jurisdiction under the opening sentence of § 1(b) that "[t]he provisions of this Act shall apply to the transportation of natural gas in interstate commerce[.][33]

Since the transportation component of a direct sale is within the Commission's jurisdiction, and since the requirement that sales must be unbundled from transportation does not establish a rate for the unbundled direct sale, the Commission has the authority to require pipelines to unbundle their nonjurisdictional direct sales from the jurisdictional transportation service embedded in that sale.[34] The Commission believes that a pipeline's direct sale of gas should be unbundled from the transportation of such gas, just as all other pipeline sales will be unbundled from transportation, because of the possibility that the jurisdictional transportation service embedded in the direct sales transactions may cause direct sales customers to prefer the pipeline's sales over sales from non-pipeline gas merchants. Finally, nothing in Order No. 636 should be read as affecting the rates that pipelines may charge for gas in a direct sales transaction.

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33. *Id.* at 637-38.

34. Mississippi River Transmission Corp. v. FERC, No. 91-1164 (D.C. Cir. July 21, 1992). (The Commission's authority over the transportation of gas in connection with an unregulated direct sale "is beyond dispute." Slip op. at 4).

4. Contracts

Tenneco argues that the Commission has disregarded private contracts by not showing that the bundled sales contracts adversely affect the public interest. CIG argues that the Commission has shown indifference to the sanctity of contracts that reflects fundamental and long-standing commercial relationships. CNG asserts that the Commission has disregarded the fundamental role of freely negotiated contracts. In addition, ANR and CNG assert that the Commission is unlawfully creating contractual relationships for the parties.

The Commission clearly has the authority to require changes in the contracts between interstate pipelines and their customers. As the Supreme Court held in *United Gas Co. v. Mobile Gas Corp.*:[35]

> The basic power of the Commission is that given it by § 5(a) to set aside and modify any rate or contract which it determines, after hearing, to be "unjust, unreasonable, unduly discriminatory, or preferential." . . . It is simply the power to review rates and contracts made in the first instance by natural gas companies and, if they are determined to be unlawful, to remedy them.[36]

The Commission has exercised this authority in Order No. 636 and has found pipeline bundled sales services to be unduly discriminatory and anticompetitive, and accordingly, has, among

35. 350 U.S. 332 (1956).

36. *Id.* at 341.

other things, changed the bundled sales contracts of pipelines into separate contracts for sales and transportation. A contract which is found to be unduly discriminatory by its very nature adversely affects the public interest and *must* be modified.

Contrary to the assertions of CIG and CNG, the Commission is not disregarding the role of contracts. In fact, one of the goals of the final rule is to allow parties to rely more on private contracts. The Commission stated in Order No. 636 that "[a]s part of the effort to foster competition in the natural gas industry, the Commission, in the final rule, is allowing the industry greater flexibility to control transactions through negotiated contracts."[37] But to achieve this objective in a manner that enables consumers to realize the long term benefits of fair competition, Order No. 636 changes parties' existing unduly discriminatory contracts.[38] As a result, the new regulatory structure created by Order No. 636 will enable parties to rely more on contracts to govern their relationships in the future and thus will occur in a commercial environment where no one segment of the industry has an unfair, regulatory advantage over other market participants. Finally, contrary to the assertions of ANR and CNG, the Commission is not unlawfully creating new contractual relationships for the parties. The Commission, by changing the terms and conditions under which service will be provided, has presented LDCs and pipelines with the option of continuing their relationship under the new regulatory structure or terminating their relationship altogether. Order No. 636 has, however, created a new regulatory structure which will enable parties to enter into new contractual relationships that serve the public interest.

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37. Order No. 636 at p. 30,444.

38. Office of Consumers' Counsel v. FERC, 783 F. 2d 206, 236 (D.C. Cir. 1986).

Appendix C

5. Record Evidence

Several petitioners, such as Arkla, ANR, Natural, CNG and Tenneco, assert that the Commission's decision to require pipelines to unbundle and offer no-notice transportation service is not based on substantial record evidence.

The Commission disagrees. The Commission's decision to require pipelines to unbundle their sales was based upon facts showing that the market was operating inefficiently, disadvantaging all segments of the industry and the consumer. These facts, which are reflected in the various tables contained in Order No. 636, show that a disproportionate amount of firm pipeline capacity is reserved for firm sales, but that pipeline sales customers prefer to buy their gas from other sellers, and have it transported using interruptible transportation, or inferior firm transportation. The 1991 Part 284 Capacity Reports for major pipelines that made bundled sales show that an average of 64.1 percent of the pipelines' total firm capacity was reserved for firm sales.[39] However, sales only accounted for an average of 18.8 percent of the total throughput on these major pipelines. These facts led the Commission to conclude that bundled sales service was causing the natural gas market to operate inefficiently, and therefore, pipeline sales should be provided separately from transportation.

In addition, as discussed elsewhere in this order and in Order No. 636, the participants in the natural gas industry, including pipelines, generally agreed at the January 22, 1992 technical conference and the comments following that conference, that no-notice transportation service could be provided by pipelines

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39. Table 2 of Order No. 636 at p. 30,399. See discussion below of Table 2.

if they retain certain operational controls over their systems. The Commission, therefore, finds that its decision to require unbundling and the provision of no-notice transportation service is based upon substantial evidence and facts in the record of this proceeding.

6. Takings Clause Arguments

CNG argues that Order No. 636 violates the Takings Clause of the Fifth Amendment to the Constitution[40] by effectively terminating sales contracts and requiring the assignment of upstream capacity to downstream firm shippers without just compensation. Natural argues that, by precluding pipelines from making bundled sales when marketers can do so, Order No. 636 is an unlawful taking without compensation because the pipelines are deprived of an ability to act efficiently as sellers.

These arguments are based on a mischaracterization of Order No. 636. First, the Commission is not effectively terminating sales contracts. As discussed above and in Order No. 636, the Commission is separating the components of bundled sales contracts into unbundled sales contracts and firm transportation contracts. Because the regulations retain the LDC's entitlement to service and the pipeline's obligation to serve, an LDC and a pipeline may agree upon the price for gas, and the firm transportation of gas to the city-gate under the no-notice transportation service. Thus, their relationship would continue under the new terms and conditions of the pipeline's blanket transportation and blanket sales certificate.

With respect to the assignment of upstream capacity to downstream firm shippers, those shippers who want upstream

40. U.S. CONST. amend. V.

capacity will be required to pay for it. If the upstream capacity is valuable to the pipeline now, it will probably be valuable to downstream shippers in the restructured environment. In addition, to the extent downstream pipelines retain unclaimed or unneeded upstream capacity even after the assignment of capacity to firm shippers, the pipeline may file to recover such "stranded" costs in an NGA section 4 filing.

Contrary to Natural's assertion that pipelines cannot act efficiently as gas sellers in an unbundled environment, pipelines will be offering the same services in the same market as other gas sellers and will be able to compete at market prices under their blanket certificates. If a firm sales customer is satisfied with its sales service, it will probably elect to continue its contractual relationship with the pipeline under the new blanket sales certificate. When a pipeline is in full compliance with Order No. 636, it will be permitted to make market-based sales under its blanket certificate. The Commission recognized that market-based pricing for unbundled sales is necessary for pipelines to compete with non-pipeline gas merchants. In addition, pipelines are not on a par with other gas sellers because of the pipelines' monopoly control of essential transportation facilities. A goal of Order No. 636 is to create an environment in which pipelines sell under similar conditions as other gas sellers so that pipelines are unable to prefer their own gas sales because they control the transportation of gas.

In sum, because Order No. 636 does not deprive pipelines of the ability to do business, but, in fact, enhances their opportunities, there is no factual foundation to reach the "takings" argument.

Appendix C

B. The Rationale

In Order No. 636, the Commission concluded that the pipelines' bundled, city-gate, firm sales service violates sections 4(b) and 5(a) of the NGA because of the unreasonable difference between the quality of the transportation embedded within the pipelines' bundled, city-gate, firm sales service and the quality of the pipelines' open access firm transportation service. In Order No. 636, the Commission described the adverse impact of that difference in quality on all segments of the natural gas industry. First, nonpipeline gas sellers are at a disadvantage *vis a vis* pipeline gas merchants in securing long-term gas supply arrangements because the nonpipeline gas sellers cannot assure delivery at the city-gate in all circumstances. This is so because the nonpipeline gas merchants' gas must move to the city gate through interruptible or inferior firm transportation. However, pipelines do not totally benefit from this situation. Indeed, the Commission showed that pipelines are disadvantaged. Pipelines must stand ready to provide gas on demand at cost-based rates that do not enable the pipelines to successfully compete with unregulated gas sellers for sales customers on an annual basis. Last, gas customers are disadvantaged because they must use interruptible transportation to move their nonpipeline gas purchases even though they are paying firm sales demand charges for the firm transportation that is embedded within the firm sales service.[41]

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41. As cited by the Commission in Order No. 636, 51 percent of the pipeline deliveries to market were through interruptible transportation as compared to deliveries to market of 21 percent pipeline sales and 28 percent firm transportation. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1991 (May 1992), from: Table A-7, Sales and Firm and Interruptible Transportation as a Percentage of Total Delivered for Market (INGAA May 1992 paper). The INGAA May 1992 paper shows that,

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Appendix C

Only a handful of the rehearing petitioners dispute the Commission's rationale for taking action under NGA sections 4(b) and 5(a). Those objections are discussed below.

1. Antitrust Criteria

CNG and Carnegie Natural Gas Company (Carnegie) argue that the Commission did not perform a proper competition analysis under relevant antitrust criteria to determine whether pipelines possess market power in the relevant markets and whether the pipelines' bundled sales service is justified by a legitimate business purpose. On the other hand, Tenneco asks the Commission to retract its finding that the bundled city-gate service is an unlawful restraint of trade because Tenneco maintains it unjustly implies a violation of the Sherman Antitrust Act.[42]

The Commission acts under NGA sections 4 and 5 to declare pipeline practices lawful or unlawful and, if unlawful, to prescribe appropriate remedies; the Commission "does not enforce or apply the antitrust laws."[43] In applying the NGA, of course, the Commission considers the policies underlying the antitrust laws, including the anticompetitive effects of interstate pipeline operations.[44] While the Commission may employ an

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in 1991, 54 percent of the deliveries to market used interruptible transportation as compared to deliveries to market of 16 percent pipeline sales and 30 percent firm transportation.

42. Petition at 6.

43. Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 741 (5th Cir. 1987).

44. *Cf.*, Gulf States Util. Co. v. FPC, 411 U.S. 747, 758-760 (1973).

analysis similar to that used in antitrust cases, the Commission does not reach or imply conclusions about violations of the Sherman Antitrust Act or any other antitrust law.

In addition, the Commission's conclusions in Order No. 636 *vis a vis* anticompetitiveness and restraint of trade should not be interpreted to imply for specific transactions any violation of the antitrust laws by pipelines. The Commission's findings and conclusions are made solely under NGA sections 4(b) and 5(a).

Finally, Congress' underlying premise in enacting the NGA was that the pipelines possessed market power in providing services. That remains true today and is the starting point for the Commission's analysis. [45] Any pipeline — including CNG — that wishes to show that it lacks monopoly or market power over its customers in the transportation services it provides is free to do so. CNG has not done so here.

2. Anticompetitive Finding

Tenneco asserts that there is no record support for the Commission's conclusion that "pipelines are exercising monopoly power at the expense of consumers."[46] Tenneco refers to the small amount of pipeline gas sales (21 percent), to the current low price of gas, and to the abundant amount of divertible gas supplies. Tenneco further contends that the failure of sales customers to convert to firm transportation was caused by the Commission's pregranted abandonment policy and not by

45. Pipelines "have market power over transportation service." Tenneco Gas v. FERC, No. 89-1786, slip. op. at 18 (D.C. Cir. July 21, 1992).

46. Petition at 4.

pipeline monopoly power. Tenneco claims that if the pipelines had monopoly power even fewer conversions would have occurred and that "conversions on individual pipelines offering bundled city-gate sales have been higher than [the] 24%" cited by the Commission.[47]

Even though CNG's contentions, as discussed in the preceding subsection, are inappropriately draped in antitrust criteria, the Commission believes it appropriate to respond to CNG's argument. CNG maintains that the statistics cited by the Commission in Order No. 636, in support of its anticompetitiveness finding, are not relevant and that the Commission has erroneously concluded that pipelines have a competitive advantage via their bundled sales service even though the pipelines are not the beneficiaries.

Atlanta Gas Light Company and Chattanooga Gas Company (Atlanta Gas) contend that the Commission has improperly relied on NGA section 5(a), a consumer protection measure,[48] to protect producers. Citizen Action similarly argues that the Commission is attempting to pass off an anti-residential consumer policy as helping consumers. Citizen Action further maintains that residential and small gas consumers cannot yet make any informed choices about purchasing gas. The National Association of State Utility Consumer Advocates (NASUCA) contends that the order will benefit large industrial and electric utility users.

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47. *Id.* at 5. Tenneco notes that "[o]n Tennessee's system, for example, 94 percent of customers have converted all or a portion of their contract demand, resulting in conversion of 50% of total sales contract demand." *Id.* n. 9.

48. *Citing* Atlantic Reg. Co. v. Public Service Commission of New York, 360 U.S. 376, 388 (1979).

Appendix C

The Commission adheres to its discussion and analysis in Order No. 636 with respect its conclusions under NGA sections 4 and 5 and, therefore, will not repeat that detailed discussion and analysis here. The Commission will, however, for emphasis, discuss a few matters.

The Commission's statutory mandate is to protect consumers of natural gas from the exercise of monopoly power by pipelines[49] in order to assure consumers "access to an adequate supply of gas at a reasonable price."[50] In addition, the Commission must protect the interests of the investors in the pipeline by providing the pipeline an opportunity to earn a return which will "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[51] As the Commission stated in Order No. 636, those consumer and investor interests must be balanced,[52] in light of the current economic, regulatory, and market realities.[53]

In Order No. 636, the Commission demonstrated that the pre-Order No. 636 structure of the pipeline industry is dysfunctional and impairs the efficient functioning of the natural

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49. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.").

50. Tejas Power Corp. v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

51. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

52. *Id.* ("The rate-making process under the [NGA] . . . involves a balancing of the investor and consumer interests.")

53. Order No. 636 at p. 30,392.

gas market with respect to all segments of the natural gas industry. That pipelines have a low share of *annual* sales and have not reaped all of the benefits does not vitiate the Commission's analysis. The Commission's focus is on the bundled, city-gate, firm sales service, and capacity reserved for that service, its unduly discriminatory nature *vis a vis* firm transportation, and the anticompetitive consequences for all segments of the industry and consumers.

The Commission believes that the statistics cited in Order No. 636 are significant because they show that, as a group, pipeline customers have not converted to firm transportation service to satisfy their needs but have, instead, retained the higher quality bundled sales service to meet their peak needs on demand. While the Commission's pregranted abandonment policy may have influenced those customers, that does not detract from the conclusion that pipeline customers have kept the annual bundled sales service to guarantee deliveries to meet their peak needs. As the Commission stated in Order No. 636, this is amply proven by the comments of those opposing mandatory unbundling.[54] Indeed, if true, Tenneco's position underscores the market power pipelines possess in transporting gas to the city-gate. Because pipelines — and only pipelines — under the pre-636 regulatory rules can deliver gas under no-notice bundled service, they, and only they, could offer superior service. Customers may have been reluctant to leave that bundled gas service because they have no other meaningful transportation alternatives. Thus, Tenneco's argument admits by implication the factual premise that led to the remedy in Order No. 636. The Commission has acted here to ensure that pipeline customers can continue to get guaranteed deliveries to meet their peak needs, but without having to buy from only one seller. The

54. *Id.* at p. 30,402.

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Commission's intent in Order No. 636 was to eliminate the unfair competitive advantage held by pipelines' bundled city-gate, firm sales service because pipelines provide their competitors for gas sales with access to a lower quality firm transportation service than that embedded within their bundled, city-gate, firm sales service.[55] Pipeline customers have chosen to retain their bundled, firm sales service and pay reservation charges to ensure that they can meet their peak needs. This is the case even though most customers prefer to buy gas throughout the year from other gas sellers and have it transported under interruptible transportation service.

Of course, some pipelines have had more conversions than other pipelines. But this is to be expected as part of the evolution of the natural gas industry discussed in Order No. 636. In any event, this does not eliminate the need to take generic action to complete that evolution to maximize the benefits of the Natural Gas Wellhead Decontrol Act (Decontrol Act).[56] It is necessary that the pipeline industry as a whole complete its evolution so as to ensure there is no obstacle to the consumers' access to a natural gas pipeline grid and to the blossoming national gas market.

The Commission rejects the contentions that it is acting to protect only producers or industrials or electric utility users and not residential or other gas consumers. As with Order No. 436, Order No. 636 "seeks to guarantee that the competitive conditions that now obtain in the 'wellhead' or gas-production

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55. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 27-28, quoting the Department of Justice on the adverse impact of a lower quality access on the ability of competitors of pipelines to compete.

56. Pub. L. 101-60, 103 Stat. 157 (1989).

market will redound to the benefit of gas consumers."[57] This will be accomplished by creating non-discriminatory no-notice transportation so that LDCs can buy gas directly from any seller of natural gas and receive an adequate and reliable supply of gas at reasonable prices in order to serve all of their customers, including residential. In Order No. 636, the Commission created a complete menu of services for all firm shippers, including LDCs, so that they can fashion arrangements best suited to meet their needs based on informed choices about the services that are available. This is in lieu of the pre-Order 636 system that binds together individual services with separate costs into one bundled service.

3. Purpose of Bundled Sales Service

Both CNG and Carnegie further argue that the Commission erred by not considering whether bundled sales service is justified by legitimate business purposes (*e.g.*, enhancing efficiency).

The Commission was not blind to the legitimate business purpose of bundled sales service. Indeed, the Commission recognized that the objective of that service — to allow firm sales customers to receive gas up to their daily contract entitlements on demand without nominating that amount or incurring a penalty — was in the public interest. However, the Commission determined that the legitimate business purpose of bundled sales service was outweighed by its anticompetitive harm because no-notice transportation could be provided for unbundled sales without the harm resulting from the bundled sales service.

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57. Panhandle Eastern Pipe Line Co. v. FERC, 890 F. 2d 435, 436 (D.C. Cir. 1989).

Moreover, CNG and Carnegie have made no attempt to quantify the efficiencies that would be lost by the unbundling of pipeline sales from pipeline transportation. It was up to them to come forward with quantifiable data to support their claim.[58] Hence, the Commission remains convinced that its action in Order No. 636 will deter and prevent the anticompetitive abuse of the bundled sales service and, at the same time, preserve the no-notice benefits of that service. That is, the Commission upholds its conclusion that unbundled sales combined with no-notice transportation is an adequate substitute for bundled sales service[59] that also provides additional benefits to the natural gas industry.[60]

4. Cost-Benefit Analysis

CNG, Carnegie, the PEC Pipeline Group (PEC Group),[61] Atlanta Gas, Illinois Power Company and Northern States Power Companies (Illinois Power) contend that the Commission did not weigh the benefits of unbundling against the costs of unbundling. For example, Illinois Power argues that the Commission erred because it did not quantify the alleged benefits of unbundling or factor into the analysis the transition costs likely

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58. *See, generally* Tenneco Gas v. FERC, *supra*, slip. op. at 34-35 and the cases cited therein.

59. *See generally* Mississippi River Transmission Corp., *supra*, slip. op. at 10.

60. Order No. 636 at pp. 30, 411-12.

61. The PEC Pipeline Group consists of Texas Eastern Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company and Algonquin Gas Transmission Company.

to result from unbundling sales service. In particular, Illinois Power argues that there is no support for the Commission's assertion that the Commission "does not *anticipate* that pipeline gas supply costs that are incurred as a result of implementing this rule will approach the order of magnitude of the take-or-pay liabilities of . . . [the Order No. 500 and 528] era."[62]

Atlanta Gas and Citizen Action argue that an analysis prepared by the Commission's Office of Economic Policy (OEP) with respect to the benefits of Order No. 636 must be made available and part of this proceeding.

The Commission is not required to "make specific findings of tangible benefits."[63] However, two points should be made. First, in Order No. 636, the Commission demonstrated that the current regulatory structure of the pipeline industry has, and will continue to have, a harmful impact on all segments of the natural gas industry and the Nation.[64] Second, the Commission took action to remedy that situation. The Commission expects that its remedy for the anti-competitive effects of the pipelines' bundled, city-gate, firm sales services will, as described in Order No. 636, have a significant beneficial impact on the natural gas

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62. Petition at 6 (emphasis in original). Illinois Power refers to the INGAA study showing gas supply transition costs of nearly $8 billion, Letter from Gerald V. Halverson of INGAA to Chairman Allday, dated July 1, 1991 and to Natural Gas Pipeline Company of America's April 23, 1992 filing in Docket No RP92-146 to recover at least $754.9 million of gas supply realignment costs.

63. FCC v. RCA Communications, 346 U.S. 86, 96, 97 (1953), *quoted in* Wisconsin Gas Co. v. FERC, 770 F. 2d 1140, 1158 (D.C. Cir. 1985).

64. Order No. 636 at pp. 30,398-30,406.

industry by furthering the creation of an efficient national wellhead market, which will yield an adequate and reliable supply of natural gas at reasonable prices. The Commission expects that any costs that may be incurred by the pipelines in implementing this rule will either reflect (1) costs associated with past contractual commitments which the industry was bound to face regardless of Order No. 636 or (2) short-term expenditures to restructure pipeline services so the industry can operate efficiently in the long-run.

The Commission did not rely on a paper prepared by the OEP with respect to the costs and benefits of adopting Order No. 636; that paper is not part of the record for this rulemaking and there is no reason to make it a part of the record. However, an OEP paper on this subject has been made available to the public.[65]

5. Generic Versus Individual Action

Cincinnati Gas, Tenneco, CNG, and Carnegie argue that the record does not support a generic or industry-wide response since the finding that pipeline bundled services are unlawful applies only to certain parts of the pipeline industry. Cincinnati Gas supports its contention by arguing that Table 2 in Order No. 636 overstates the percentage of sales capacity to total capacity. Table 2 indicates that percentage to be 64.1 percent. However, Cincinnati Gas maintains that the correct percentage is 39.7 percent. Cincinnati Gas adjusted the Commission's figures to account for four pipelines with no sales service which were not included in Table 2, 50 percent standby service on

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65. Costs and Benefits of the Final Restructuring Rule, Office of Economic Policy, FERC (Washington, D.C.), Spring 1992.

various pipelines,[66] and conversions subsequent to the Table 2 data.

The Commission may proceed by rulemaking or by adjudication.[67] Here, the Commission has elected to proceed by rulemaking because it views the industry-wide anticompetitive circumstance to be of sufficient breadth and complexity to necessitate industry-wide action in a timely and coordinated manner. The fact that a few pipelines have unbundled their sales and transportation services does not lessen the need to take generic action to complete the evolution of the pipeline industry as a whole to ensure there is the open access to the national gas pipeline grid needed to support the national gas market envisioned by Congress when it enacted the Decontrol Act. Cincinnati Gas' revisions to Table 2 do not undermine the Commission's analysis in that it was appropriate to exclude pipelines with unbundled services to show the magnitude of the problem in the bundled part of the pipeline industry, which is a significant number of pipelines. In addition, the 50 percent standby services should not be included as unbundled sales because the LDC can still take the bundled, city-gate, sales service and the stand-by service is not equivalent to that service. Last, even 39.7 percent is a significant ratio of sales capacity to total capacity when pipeline sales accounted for only 18.8 percent of throughput.[68] In short, under the most conservative

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66. Under 50 percent standby service, a firm sales customer may elect to receive 50 percent of its daily contract demand volumes as firm transportation service for the shipment of gas purchased from any gas suppliers.

67. Wisconsin Gas Co. v. FERC, 770 F. 2d 1140, 1166 (D.C. Cir. 1985).

68. Order No. 636 at p. 30,399, Table 2. Cincinnati Gas further states (Cont'd)

estimate, gas customers are paying for more than twice the amount of capacity than they actually need for pipeline sales services.

CNG and Carnegie also argue that the Commission has not shown that its anticompetitiveness finding applies to them. Similarly, PGT argues that there is no record evidence that would substantiate a finding of undue discrimination against PGT's present tariffs or operations, or which would justify the ban against sales by PGT at the interconnection of its facilities with those of its sales customers.

Because the Commission is determining rules of "general, prospective applicability" to solve "systemic problems of the natural gas [industry]",[69] it does not need to examine the circumstances of individual pipelines.[70] Rulemaking is the appropriate vehicle for receiving industry-wide comment and data on rules fashioned to improve the competitive structure of

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(Cont'd)

that only 6 out of the 20 pipelines on its revised table have sales contract demand volumes above 50 percent of total capacity. As a result, it claims, the disparity between reserved sales capacity and actual use is a problem that exists only in isolated pockets and does not support an industry-wide solution. Cincinnati misses the major point that the percent of capacity reserved for sales in isolation is meaningless. It is useful only when compared to the percent of capacity actually used for sales. Even on its revised table, 14 out of the 20 pipelines have a percent of capacity reserved for sales that is higher than the average of about 20 percent of throughput being used for sales. In addition, the reduced percentages result in part from the adjustment for standby service.

69. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1166 (D.C. Cir. 1985).

70. *Id.* at p. 1165-68; Associated Gas Distributors v. FERC, 824 F.2d 981, 1008 (D.C. Cir. 1987).

open access transportation on a generic basis.[71] In Order No. 636, the Commission concluded that, in the current environment, pipeline bundled, city-gate, firm sales services on an aggregate basis are unduly discriminatory because the transportation embedded within the firm sales services is superior to firm transportation. This circumstance has an adverse impact on the efficient national interstate gas market and individualized findings are not necessary.[72] Individual circumstances are appropriately considered in the individual restructuring proceedings. Hence, this order will not consider whether certain pipelines should be excepted from any of the requirements adopted by Order No. 636 or resolve issues that are pipeline-specific rather than of a generic nature. Those matters will be considered in the individual restructuring proceedings and compliance filings.[73]

6. No-Notice Transportation

CNG and Carnegie maintain that they cannot provide a reliable no-notice transportation service. Atlanta Gas argues that the Commission should have provided record evidence to demonstrate that pipelines can perform this service. The APGA, and the Tennessee Small General Service Customers Group and the Columbia Small Customer Group (Tennessee and Columbia

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71. Wisconsin Gas Co, 770 F.2d at 1166 n. 36.

72. AGD, 824 F. 2d at 1000 n. 4 and 1008 (The Commission is not required to make individualized findings if it exercises its section 5 authority to take generic action because any tariff violating the rule would have an adverse effect on the interstate gas markets).

73. The Commission has already issued several orders exempting pipelines from Order No. 636. *E.g.*, Freeport Interstate Pipeline Co., 59 FERC ¶ 61,378 (1992).

Small Customers) object to the elimination of bundled, sales service for what they maintain is a hypothetical, theoretical, untested no-notice transportation service. Natural argues that the Commission did not engage in reasoned decision making by mandating an untried no-notice transportation service where there can be no guarantee that the new system will prove as reliable as that currently in place.

The Commission believes it is fully warranted in its prediction that the pipelines can provide a reliable no-notice transportation service. The pipelines themselves individually, and through INGAA, their trade association, provided the evidence at the January 22, 1992 technical conference, that pipelines can provide no-notice transportation service.[74] This is further attested to by INGAA's statement that "INGAA believes that the pipeline and its customers can design a no-notice transportation service to provide customers with the same degree of reliability as previously available from a pipeline's bundled merchant service."[75] The Commission sees no rational basis why, as stated by INGAA, pipelines cannot perform a no-notice transportation service. They provided no-notice service as part of their bundled, city-gate, firm sales service. The changing of the place of sale and, in some instances, the identity of the seller of the gas, should not change the ability of pipelines to deliver the gas on a no-notice basis. Thus, the concerns about no-notice transportation are unsupported and premature.[76] The parties should first address the no-notice transportation mechanics in their restructuring proceedings before a pipeline argues that it

74. Technical Conference Tr. 36-38.

75. INGAA's Petition at 10.

76. *Cf.* Northern Indiana Public Service Company v. FERC, No. 90-1528, (D.C. Cir., Jan. 21, 1992).

is impossible to provide a no-notice transportation service.[77]

7. Different Remedy

Cincinnati Gas suggests that the Commission could have selected a less intrusive remedy by mandating that pipelines implement 100 percent standby transportation service within firm sales entitlement levels.

The Commission believes that Cincinnati Gas' suggested remedy would not be in the public interest. Retaining the bundled, city-gate, firm sales service would mean that other gas sellers would not be competing with the pipeline on an even basis because they could not offer the same sales services on the same basis. For example, the pipeline could make sales at the city-gate while other gas sellers would have to sell at the production area. Even assuming that the standby transportation is no-notice transportation, the pipeline will still have the natural incentive to favor itself in managing the pipeline system. A major purpose of the Commission in adopting Order No. 636 is to design rules to counter that economic incentive to discriminate in favor of a pipeline's own bundled sales service.[78]

Moreover, the implementation of 100 percent standby transportation service would continue the problems that Order No. 636 identified and sought to correct. That is, pipelines would remain liable to provide firm sales service and keep under contract the gas necessary to provide the service, even though the customer is taking the gas from the pipeline only at peak. This would tie up reserves and lead to higher prices and increased

77. See *infra* for a discussion of "no-notice" transportation.

78. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 27-28, discussing the pipeline's "obvious incentive to favor its own marketing affiliate."

pipeline exposure to take-or-pay liability. It is more efficient to unbundle pipeline sales and capacity so that the pipeline can know exactly what are its obligations to its sales customers, maintain the necessary gas supply portfolio to meet those obligations, and fashion its sales rates accordingly.

8. Reliance on the Decontrol Act

Indiana Gas Company, Inc. (Indiana Gas), Tenneco, and Arkla argue that the Commission improperly relied on the Decontrol Act to support its decision to unbundle sales and transportation services. For example, Arkla argues that the Decontrol Act did not change the NGA, did no more than eliminate wellhead price controls on the first sale of natural gas, and does not support the Commission's drastic changes to the present pipeline regulatory structure. Indiana Gas adds that the generalized legislative intent of the Decontrol Act does not support the radical restructuring of Order No. 636.

The Commission recognizes that its mission under the NGA to protect consumers was not changed by the Decontrol Act. Indeed, as the Commission stated in Order No. 636, "[t]he Decontrol Act did not . . . alter the NGA's consumer protection mandate."[79] The Commission cited the legislative background to the Decontrol Act merely to show Congressional intent that the Commission act in accordance with the competitive conditions recognized by Congress in enacting the Decontrol Act, and not as evidence of a new statutory mandate. Indeed, the House Committee Report stated that the Commission's "current competitive 'open-access' pipeline system [should be] maintained" and further described the importance of open-access transportation as follows:

79. Order No. 636 at p. 30,3097.

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> The Committee stresses that these new rules, and especially the wide adoption of blanket certificates for nondiscriminatory open-access interstate transportation of nonpipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest selling producer, and obtain shipment of its gas to them on even terms with other supplies.[80]

The House Committee Report further urged the Commission "to retain and improve this competitive structure in order to maximize the benefits of decontrol."[81] The Commission exercised its NGA consumer protection mandate by "seek[ing] to guarantee that the competitive conditions that now obtain in the 'wellhead' or gas-production market will redound to the benefit of the gas consumers."[82] The Commission did this by fashioning an open access transportation network where all gas sellers have equal access to that regulated essential service to ensure efficient competition in the gas sales market.[83]

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80. H.R. Rep. No. 29, 101st Cong., 1st Sess., at p. 6.

81. *Id.*

82. Panhandle Eastern Pipe Line Co., 890 F.2d 435, 436 (D.C. Cir. 1989).

83. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 28, quoting the Department of Justice on the adverse impact on pipeline competitors for gas sales of a lower quality of access to transportation.

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IV. UNBUNDLING

A. Pipeline Access to Capacity

In Order No. 636, the Commission concluded that pipelines must unbundle the sales and transportation components of their bundled, city-gate, firm sales service. On the effective date of the pipeline's Order No. 636 compliance filing, each bundled sales customer's firm sales entitlement will be converted to an equivalent amount of unbundled firm sales service and to an equivalent amount of unbundled firm transportation service,[84] except as adjusted in the pipeline's restructuring proceeding. In addition, the pipeline must provide access to downstream storage and may retain downstream storage only for system management and balancing and no-notice transportation purposes.[85] Furthermore, downstream pipelines must make available capacity they hold on upstream pipelines to the downstream pipeline's customers, if requested.[86]

Several petitioners argue that the pipelines should be allowed to retain or obtain capacity rights so that they can compete on an equal basis with other gas sellers who can obtain capacity.[87] For example, INGAA argues that "[o]nce a pipeline has fully unbundled, its merchant division should be able to

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84. Conversions and adjustments are discussed *infra*.

85. Storage is discussed *infra*.

86. Upstream Capacity rights are discussed *infra*.

87. *E.g.*, INGAA, Natural, Marathon Oil Company (Marathon), Tenneco, KN Energy, Inc. (KN), ANR, Texas Gas Transmission Corporation (Texas Gas), and Questar Pipeline Company (Questar).

contract for uncommitted capacity, take assignment of capacity under the capacity releasing programs and gain access to the no-notice service not subscribed by LDCs, as long as the pipeline honors the terms and conditions of service quality."[88] Natural is concerned that it cannot make city-gate sales, which puts it at a disadvantage *vis a vis* other marketers in providing a gas delivery service using rebundled transportation and storage.

The Commission concludes that a pipeline cannot retain or obtain capacity downstream of the point of unbundling on its system except for storage as needed for system management and balancing and no-notice transportation purposes. More importantly, pipelines will be able to make sales in competition with other gas sellers. Assume that a pipeline has uncommitted capacity. Assume further that a gas customer wants to purchase gas from the pipeline. The pipeline then enters into an unbundled gas sales contract with its new customer, and a separate transportation agreement to ship the gas. In addition, the pipeline may act as the gas purchaser's agent and make all arrangements necessary for transportation of the gas. In this manner, the pipeline can compete, while maintaining the competitive and economic benefits that unbundling brings to the market place. And while it is true that their competitors can obtain such capacity either from the pipeline directly or via the capacity releasing mechanism, the Commission believes that on balance any advantage on a generic basis for those competitors will be minimal and does not warrant permitting pipelines to be capacity holders and gain the opportunity to favor themselves as gas sellers in the management of pipeline transportation facilities, including storage.[89]

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88. Petition at 10.

89. *Cf.* Tenneco Gas v. FERC, *supra*, *slip*. op. at 17, 18, 27, 28 for a (Cont'd)

B. Agency

In Order No. 636 the Commission held that a pipeline or any other merchant may act as the gas purchaser's agent in making all arrangements necessary for the gas to be transported and delivered to the gas purchaser. Order No. 636 also provides that a pipeline acting as agent may receive a negotiated agency fee as part of its unregulated sales service and must act on a nondiscriminatory basis.

Texas Gas asks the Commission to clarify that the pipeline merchant when it acts as a customer's agent in packaging pipeline services may repackage the unbundled sales and unbundled transportation by contract in such a manner that the actual title transfer is at a pooling point or market center, even if the point is downstream of the initial point of unbundling where the transportation service was separated from the sales service. Texas Gas adds that the unbundled transportation service would continue to be provided on a non-discriminatory basis originating at the point of unbundling and that the pipeline merchant service, as agent, would simply be permitted to act in a fashion similar to other merchants aggregating supplies.

The Commission denies Texas Gas' request for clarification. It is not clear why Texas Gas needs to retain title to its gas beyond the point of unbundling. First, all agents (including the pipeline and other gas sellers) act on behalf of their principal, the gas purchaser. It is the principal that holds title to the gas and holds the right to use the pipeline capacity. Hence, all agents are similarly situated. With respect to aggregating supplies, the

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discussion of the pipeline's "obvious incentive to favor its own marketing affiliate" (at 27).

parties to a particular pipeline's restructuring proceeding may consider and agree to "paper" pooling areas near the production area for the purposes of aggregation and balancing and the determination of penalties for all sellers of gas, including the pipeline.[90] In addition, a pipeline's marketing affiliate could obtain capacity and retain title to gas in the same manner as nonaffiliated gas sellers, subject to Order No. 497's standards of conduct and reporting requirements.[91]

ANR asks for clarification that the non-discrimination standard would not preclude the negotiation of different levels of agency fees, and that there would be no limitation as to the operating division of the pipeline which would be able to act in an agency capacity.

The Commission provided in Order No. 636 that the pipeline can act as an agent as part of its unbundled sales service.[92] In addition, the Commission concluded that the pipeline's fee, if any, was a matter for negotiation between it and the gas purchaser on entering into their sales contract, and that the fee would be received as part of the price for selling gas and not as part of the transportation rate. Last, the Commission stated that the pipeline

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90. At a paper pooling point, title to the gas may transfer to multiple purchasers from one seller even though there are no interconnections with other pipelines at that point. No penalties are assessed to any of the purchasers as long as their aggregate scheduled volumes equal the aggregate volumes transferred at the point from the seller to the multiple purchasers.

91. *See*, n.3, *supra*.

92. 18 CFR 284.284(d) ("A pipeline that provides unbundled sales service under this section may serve as an agent of the sales customer to arrange for any pipeline-provided service necessary to deliver their gas to the customer.")

must act in a non-discriminatory manner in offering agency services.

The Commission clarifies that the pipeline may not discriminate in providing the agency service but that the fee amount is a matter for negotiation. The Commission further clarifies that the pipeline's sales division must provide the agency service. This will ensure that all gas sellers compete on an even basis in connection with the providing of agency services. If a pipeline has no formal sales division, the agency service must be provided by its sales operating employees as an operational unit.[93]

C. Small Customer Service

In Order No. 636, the Commission did not adopt the NOPR's proposal to continue a bundled, city-gate, firm sales service for small customers. The Commission stated that those customers can be served reliably through a combination of unbundled sales, the no-notice transportation service, and the use of the pipeline or some other gas seller as the gas purchaser's agent to make all the arrangements necessary to deliver the gas to the small customer in the same manner as under the bundled, city-gate, firm sales service. In addition, the Commission stated that the small customers could continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined.

APGA, the State of Louisiana, City Gas Company (City Gas), and the Tennessee and Columbia Small Customers argue

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93. See 18 CFR 284.286.

that the Commission erred in failing to exempt small customers from mandatory unbundling. They maintain that small customers do not have the ability to operate in an unbundled environment to secure their former reliable service at a reasonable, negotiated rate. They are concerned about maintaining service without any supply disruptions and about their disadvantage in bargaining for just and reasonable gas prices.

The Tennessee and Columbia Small Customers also argue that the Commission gave no reason why the continuation of bundled sales service for small customers would interfere in a material way with implementation of Order No. 636.

As discussed below, the Commission is sympathetic to the concerns raised by small customers. The Commission will make several changes to Order No. 636 to address those concerns. As a result, the Commission does not think it is necessary to grant rehearing as to the request to make an exception to unbundling for small customers but will grant rehearing to make other adjustments for small customers (as discussed, *infra*). The Commission does not grant rehearing on this point for several reasons. First, the Commission believes that there should be no exceptions to unbundling. As stated earlier, an exception would mean that all gas sellers would not be competing on an even basis by offering the same sales services in the same production area market. Second, an exception is not needed for small customers because they can be served reliably through a combination of unbundled sales, no-notice transportation, and agency services. Those services will enable the small customers to receive gas when needed to serve their customers on a reliable and timely basis (see *infra* on no-notice transportation service). In addition, the competitive sales market will keep the prices reasonable for gas and agency services of both pipeline and non-pipelines gas merchants. Should the small customers believe

that the pipeline prices are not reasonable, because of the exercise of market power, they may seek appropriate relief from the Commission.

Moreover, as discussed below, the Commission is adopting a one-year transitional period (from the effective date of the pipeline's blanket certificate) with respect to pipeline gas prices for small customers only.[94] During that period, the Commission is requiring pipelines, under their blanket sales certificates granted by Order No. 636, to sell gas to those customers that elect to purchase gas from the pipeline at rates that are cost-based. The Commission is doing this in order to give small customers adequate time to make alternate supply arrangements. For example, they may need more time to arrange to aggregate their gas purchases from different suppliers. As discussed below, the Commission will monitor those rates under the blanket sales certificates.[95] And, the Commission recognizes those customers' unique status by requiring pipelines to provide this cost-based service only for the small customers.

City Gas asks the Commission to clarify that pipelines will be required to compute small customer transportation rates on a one-part volumetric basis at the imputed load factor underlying the pipeline's currently effective small customer sales rate. The Commission is granting rehearing to require pipelines that, on May 18, 1992, offered a small customer sales or transportation service on a one-part volumetric basis at an imputed load factor to offer all its firm transportation services, including no-notice transportation, on the same basis, including the same eligibility

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94. This one year transition period will effectively give small customers two years to plan and adjust to their new responsibilities under Order No. 636.

95. Issues with respect to pregranted abandonment are discussed infra.

criteria, to small customers. In addition, the Commission is requiring those pipelines to consider in the restructuring proceedings enlarging the size of the small customer class from its existing size up to 10,000 Mcf or Dth/day. In the Commission's judgment, this will continue to protect the small customers. But the Commission will not give them a special marketing advantage. Therefore, the Commission will preclude the small customer from shipping gas under available interruptible transportation service on the pipeline or from shipping gas as a replacement shipper under the capacity releasing mechanism before it exhausts its firm entitlement to service under a small customer rate schedule.[96] The pipeline's tariff cannot be any more restrictive than the restrictions specified in this Order. The rates revised as part of the compliance filing must continue to maintain existing small customer classes as part of the transportation rates. The rate for the small customer class must be computed using a load factor no less than the load factor used to compute the existing small customer rate (see rate discussion *infra*) because the Commission did not direct the elimination of those rate differentials in Order No. 636.

V. OPEN ACCESS TRANSPORTATION RULES

This Part addresses the rehearing and clarification requests with respect to the essential aspects of, and terms and conditions for, open access transportation.

A. Transportation Equality

Order No. 636 adopted new regulations §§ 284.8(b)(2) and 284.9(b)(2) to require an open-access pipeline that offers firm

96. These conditions are explained below in the Transportation Rates section.

and interruptible service to provide those services on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere. While Order No. 636 did not adopt a uniform code of terms and conditions of service, it did codify two general principles in the regulations and did state that a pipeline must have tariff provisions governing, at least, certain named transportation matters. This part V.A.addresses issues raised with respect to terms and conditions of service.[97]

1. Current Contracts

INGAA asks the Commission to clarify that pipelines can renegotiate with current shippers in order to establish operating terms and conditions and to reflect the new competitive situation. The Commission clarifies that pipelines can, subject to Commission approval in the restructuring proceedings, propose and renegotiate changes to their operating terms and conditions which are related to complying with Order No. 636.

2. Definition of Capacity

Peoples Gas System, Inc. (Peoples Gas) argues that the pipelines must be required to define "capacity" as an operating term in their tariffs so that the parties to the restructuring proceeding have an empirical definition. While the amount of capacity available is important in allocating capacity among shippers, the Commission will not require a definition of capacity in pipeline tariffs. Issues involving the amount of capacity are pipeline-specific matters that will vary by pipeline and by season. Of course, capacity must be decided in light of generally accepted engineering standards. The Commission will require the pipelines to address this issue in the restructuring proceedings.

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97. Flexible receipt and delivery point issues are discussed, *infra*.

Appendix C

3. Imbalances Penalties

Destec Energy, Inc. (Destec) asks the Commission to state that to the extent a pipeline has positive and negative imbalances existing simultaneously on its system, that such imbalances should be netted out, for penalty purposes, on a pro rata basis with imbalance penalties imposed only upon those shippers who remain out of balance after such netting out.[98] The Fuel Managers Association makes the same netting out argument: "If the pipeline experiences an excessive net imbalance during a month, only those customers that accrue an excessive monthly imbalance of a similar nature as the pipeline's excessive net imbalance, *i.e.*, a positive or negative imbalance, should be penalized for their monthly imbalances."[99]

Without reaching the merits of this particular argument, the Commission observes that penalties are a matter to be resolved in the restructuring proceedings and not for generic action. The pipelines' penalties are, of course, subject to the equality principle.

The Industrial Groups[100] argue that with the adoption of SFV for rate design, pipelines should not be able to retain penalty or cashout revenues that would enable them to profit more from penalties than from throughput. The Commission sees no

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98. The American Paper Institute, Inc. (American Paper Institute) makes the same argument.

99. Petition at 24.

100. Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufactures Association, and California League of Food Processors.

relationship between SFV and penalties, which are designed to inhibit action that is inimical to the operational integrity of a pipeline system.

Consolidated Edison Company of New York, Inc. (ConEd) is concerned about multiple pipeline imbalance penalties for pipeline to pipeline deliveries where it delivers its scheduled amount into the first pipeline and takes that amount from the last pipeline but intermediate deliveries are over that amount. It argues that pipelines participating in those interactions should bear the responsibility for deliveries from pipeline to pipeline and suggests that the Commission require pipelines to establish in their tariffs scheduling and balancing procedures for multiple pipeline interactions.

Without ruling on the merits of ConEd's argument, the Commission concludes that this is a matter for the restructuring proceedings and not for generic action. The Commission observes, however, that this appears to be a matter between the upstream pipeline and its shipper about the extent of the former's liability for downstream penalties.

4. Interconnection Priority

Amoco Production Company (Amoco) argues that it is necessary to require that a shipper's type of transportation on a downstream pipeline should control access to the downstream pipeline without regard to the type of transportation used on the upstream pipeline.[101] It states that "this principle should be

101. It provides this example: "if interruptible transportation feeds downstream firm transportation, the priority at the interconnect point would be superior to other interruptible transportation at that point. If firm transportation feeds downstream interruptible transportation, the priority at

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applicable to gathering feeding mainline transportation, to upstream pipeline arrangements interconnecting with downstream pipelines, and to upstream arrangements with one shipper feeding downstream arrangements to another shipper all on the same pipeline."[102]

Brymore Energy, Inc. (Brymore) sets out an elaborate statement of priorities and asks the Commission to either order its suggested priorities to be implemented on all interconnects with interstate pipelines, or, in the alternative, to call a technical conference to establish such priorities.[103]

The Commission will not, as part of this generic rulemaking, mandate interconnection priorities. Those priorities involve terms and conditions of service. As such, they must be developed and established according to the equality principle that pipelines must provide their services on a basis that is equal in quality for all gas supplies transported under that service. However, the details of the terms and conditions of service are matters that must be addressed in the restructuring proceedings.

5. Upstream/Downstream Fuel

ConEd is also concerned about upstream and downstream

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the interconnect point would be inferior to other firm transportation at that point." Petition at 3.

102. *Id.*

103. Brymore's priorities include both scheduling and curtailment and it set forth priorities for interconnections between interstate pipelines and LDCs' interstate pipelines and non jurisdictional supply facilities and interstate pipelines.

fuel requirements and their impact on contract quantities. It believes it should be able to adjust contract quantities to reflect changed fuel requirements in order to maintain city-gate quantity levels. It suggests that pipeline tariffs and service agreements should provide firm customers with the right to adjust contract quantities to correspond to changes in upstream and downstream fuel requirements, that such changes should not be treated as part of the pipeline's transportation queue for service, and that the design of pipeline facilities should take such flexibility into consideration.

Without reaching the merits of this argument, the Commission concludes that fuel requirement issues are matters that must be considered in the restructuring proceedings.

6. Multiple Pipeline Gas Quality Specifications

ConEd is also concerned about pipeline gas quality specifications. It states that in multiple pipeline transportation "pipelines are best positioned to resolve differences in quality specifications and in quality levels at pipeline interconnects."[104] It states that "upstream pipelines engaging in multiple pipeline interactions must assume the responsibility of delivering to the downstream pipeline gas which meets the quality specifications contained in the downstream pipeline's tariff [and] . . . pipelines agreeing to provide downstream service must agree not to unilaterally change their quality specifications where such changes would be inconsistent with the quality specifications of the upstream pipeline and would thereby result in rejection of gas tendered."[105]

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104. Petition at 7.

105. *Id.* at 7, 8.

The Commission concludes that gas quality specification issues are matters that must be considered in the restructuring proceedings.

7. First-Come/First Served Queue

Tejas Power Corporation (Tejas) argues that existing first-come, first-served queues for firm or interruptible transportation queues should be abolished in conformity with the Commission's right of first refusal mechanisms, which are designed to allocate capacity to customers who value it the most. Tejas recommends replacing the first-come, first-serve queue with a "system of bidding for priority of service" or "at a minimum . . . the formation of new queue on a regular basis after implementation of the Rule."[106] It adds this is especially important for interruptible queues.

Northern Indiana Public Service Company (Northern Indiana) argues that interruptible service priority rights based on queue dates must be eliminated. It maintains that the grandfathered queue dates will give certain shippers power over capacity, leaves the door open to unregulated capacity brokering and buy/sell arrangements, and could discourage new entrants into the gas market. It argues that if the Commission does not abolish queue date priorities, it must require pipelines to publish existing queue lists for interruptible transportation and storage services along with a utilization history.

Without reaching the merits of Tejas' or Northern Indiana's arguments, the Commission will not address prematurely here any queue issues as they relate to capacity obtained from the pipeline. The Commission notes that the pipelines *must* post

106. Petition at 10.

available firm and interruptible capacity on their electronic bulletin boards so that potential shippers may choose between pipeline and released capacity. How the pipelines allocate their own capacity among multiple aspirants for that capacity is an issue that must be considered in the restructuring proceedings. If a dispute arises during the restructuring discussion that cannot be resolved by the parties, the Commission will resolve those disputes when the pipeline makes its scheduled compliance filing, or earlier, if brought before the Commission. The Commission further notes that mandatory implementation of capacity release mechanisms on the pipelines may affect queues because released capacity will be a significant alternative transportation option for acquiring transportation capacity.

8. Security of Service

Brooklyn Union Gas Company (Brooklyn Union), *et al.*[107] argue that "security of service" issues must be addressed by the Commission, that is, the "pipeline [must] be responsible for redelivery at the city gate of quantities of gas equivalent to those delivered into the pipeline by or for, each firm transportation shipper, even in the event of overruns by other shippers."[108] They state that the pipeline must use or impose tools to discipline the system, for example, "the installation of real time metering equipment, the development of predetermined allocation procedures, and the availability of dispatchers on a twenty-four hour basis" and "meaningful [overrun] penalty charges."[109]

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107. ConEd and Public Service Electric and Gas Company (PSE&G).

108. Petition at 7.

109. *Id.* at 7 n. 7 and 8.

The Commission agrees with Brooklyn Union, *et. al.*, that, as a general matter, pipelines are responsible for delivering to shippers the amount of gas injected into the pipeline. These issues involving this responsibility, such as exceptions and disciplinary tools, must be considered as part of the restructuring proceedings.[110]

B. Electronic Bulletin Boards

Order No. 636 requires pipelines to provide timely and equal access to all information necessary for buyers and sellers to arrange for capacity reallocation and requires this information to be provided on electronic bulletin boards (EBB). American Paper Institute, Brymore, ConEd, Industrial Groups, Kern River Pipeline Co. (Kern River), Mobil Natural Gas Co. (Mobil), Natural Gas Clearinghouse, Natural Gas Supply Association/ Indicated Producers (NGSA), New Jersey Natural Gas Co. (New Jersey Natural), PSE&G, and UGI Utilities (UGI) seek rehearing or clarification of the requirements for EBBs.

Several petitioners[111] argue that the Commission erred in failing to adopt uniform national standards for EBBs. These parties assert that uniform standards are necessary to eliminate inefficiencies and promote development of market centers. They assert that without standardization of interfaces and formats, access to many EBBs will be very costly. Brymore Energy asks the Commission to establish a Task Force to act as a catalyst in

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110. The Commission rejects Cincinnati Gas' request that the Commission impose a Uniform Gas Day, because the Commission has no jurisdiction over most production area gas sales.

111. American Paper Institute, Brymore, Natural Gas Clearinghouse, NGSA, and New Jersey Natural.

the process of developing standards, and Natural Gas Clearinghouse asks the Commission to establish a technical conference for this purpose.

During the past year, the Commission's staff has been auditing the performance of and access to pipeline EBBs. Based upon that information, the Commission agrees that standardization of information content, display formats, and software is extremely important and would greatly enhance the efficiency of the capacity release program to the benefit all users of the pipeline system. The Commission believes that the lack of uniform standards can hamper efficient movement of gas across pipelines and can inhibit the development of market centers. The Commission, however, does not have sufficient information at this time to prescribe and mandate uniform standards beyond those contained in Order No. 636. The Commission strongly encourages the industry to develop its own uniform standards and conventions for use of EBBs without Commission intervention. Although the Commission will not initiate a generic proceeding to address appropriate uniform standards at this time, the Commission will hold a technical conference in the near future in order to determine the progress made by the industry in developing interactive, user-friendly EBBs and uniform standards.

American Paper Institute, ConEd, Mobil and NGSA ask the Commission to require the pipeline to include the terms and conditions for access to EBBs in their tariff filings. These parties assert that access agreements are often one-sided and the Commission should review the pipelines' tariffs to assure that they are reasonable and non-discriminatory.

The Commission agrees. The terms and conditions of access

to EBBs must be just and reasonable and must be included in the pipeline's tariff. The Commission directs the pipelines to include these provisions in the compliance filings.

American Paper Institute asks the Commission to clarify the EBBs must be operational and meet the Commission's criteria no later than the effective date of the pipeline's tariff filing implementing Order No. 636. Rochester Gas & Electric (Rochester Gas) asserts that the EBBs must be operational as soon as possible, even before the pipeline is in compliance with Order No. 636.

In some cases, pipelines may implement capacity releasing prior to implementing the remainder of the restructuring requirements.[112] The Commission clarifies that the appropriate date for EBBs to go on-line is no later than the effective date of the tariff sheets implementing the capacity releasing mechanism.

The standards of conduct adopted in this rule require that to the maximum extent practicable, the pipeline's transportation employees and its gas marketing employees must function independently of each other.[113] The EBB is part of the transportation function and, thus, the regulations already require that the EBB personnel function independently of the gas marketing personnel to the maximum extent practicable. Because the EBB is an integral part of the transportation operation, further separation is not feasible.

Rochester Gas raises the issue of the proprietary nature of

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112. Northern Natural Gas Co., 59 FERC ¶ 61,362 (1992); Northern Border Pipeline Co., 59 FERC ¶ 61,312 (1992).

113. 18 CFR 284.286.

EBB information by stating that it assumes pipelines will permit anyone to access, download, and disseminate data from the EBBs. The Commission clarifies that it does not consider the information that must be on the EBB to be proprietary.

Mobil argues that the EBBs should be interactive, and that a potential capacity buyer should be able to respond to the offer and close the deal on the EBB without intervention of the pipeline. The Commission believes that interactive EBBs will enhance the efficiency of the system and, therefore, directs pipelines to provide for interactive bulletin boards if feasible on the particular system. A pipeline must explain in the restructuring proceeding why it believes that an interactive EBB is not appropriate on its system.

Kern River asks the Commission to clarify that historical information does not have to be accessed on the bulletin board, but can be maintained off-line. The request for clarification is granted. Historical data does not have to be accessed on the EBB. As the Commission stated in Order No. 636, the pipeline must keep daily back-up records of the information displayed on their EBB for at least three years, and should permit users to review those records, which should be reasonably accessible.[114] In addition, Order No. 636 provides that pipelines must periodically purge completed transactions from current files so that EBB users do not have to sift through massive amounts of historical data to find current information.[115] Archived information should be available for a reasonable fee in electronic form. Pipelines are directed to include procedures for back-up, archiving, and retrieval in their tariffs.

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114. Order No. 636 at 68.

115. *Id.*

Appendix C

C. Capacity Reallocation

In Order No. 636, the Commission adopted, in new sections 284.242 and 284.243, two new capacity reallocation programs. The Commission announced that it will not approve new individually authorized capacity brokering and other capacity assignment mechanisms. The Commission, in a separate order issued April 8, 1992, amended the terms and conditions of existing capacity brokering and other assignment programs to conform to the capacity reallocation regulations adopted in Order No. 636.[116] However, the Commission allowed capacity assignments and reassignments in effect on the effective date of a pipeline's capacity reallocation mechanism to continue in effect, provided the original capacity holder retains its capacity through the restructuring proceeding mechanism. In addition, all capacity assignments must be done under the new mechanisms once they become effective. This includes buy/sell arrangements where an LDC purchases gas in the production area from an end user or merchant designated by an end user, ships the gas on its (the LDC's) own capacity, and sells the gas to the end user at the retail delivery point.[117] The Commission, however, permitted buy/sell arrangements in effect on the effective date of a pipeline's capacity reallocation program to continue in effect provided the LDC retains its capacity through the restructuring mechanism. In addition, the Commission required that the pipeline post particulars of the buy/sell deals on its electronic bulletin board to make those transactions public.

As a general matter, the Commission denies rehearing on these issues. However, the Commission will make several

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116. Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992).

117. El Paso Natural Gas Co., 59 FERC ¶ 61,031 (1992).

changes on rehearing to the capacity assignment mechanisms. The most significant change is that shippers can release capacity for any period of less than one calendar month without prior posting on the EBB or bidding for the released capacity. Those releases must be announced on the EBB as soon as possible after the transaction commences, but no later than forty-eight hours,[118] and no roll-overs or extensions will be permitted without prior notice and opportunity to bid for the capacity.

1. Jurisdiction Over Capacity Brokering Activities

The Public Service Commission of the State of New York (New York PSC), Atlanta Gas, and UGI maintain that the Commission has no jurisdiction over the assignment of capacity rights by an LDC to a customer on the LDC's system because the LDC is not a jurisdictional transporter of gas. APGA contends that the Commission has no authority to require municipalities to comply with the section 284.243's capacity releasing procedures and limitations because municipalities are not subject to Commission jurisdiction under either the NGA or the NGPA.

The Commission rejects the contention that it lacks jurisdiction over the assignment of capacity by LDCs. In *Texas Eastern Transmission Corp.*,[119] the Commission resolved the jurisdiction question as follows:

> Since the brokering, or assignment, of

118. The Commission believes that forty-eight hours is an appropriate and feasible period for requiring posting unless a pipeline can demonstrate that some short extension of the maximum time is necessary for operational reasons.

119. 48 FERC ¶ 61,248 (1989), *order on reh'g*, 51 FERC ¶ 61,170 (1990).

> transportation capacity will control the access to that capacity, the Commission believes that brokering is tantamount to transportation. Therefore, brokering constitutes a new transportation service, subject to the Commission's jurisdiction, that is not covered directly by existing NGA section 7(c) transportation authorizations.[120]

The Commission amplified that analysis in the rehearing order by stating that there will be a movement of gas in interstate commerce by the assignee of capacity rights, "[B]y controlling such capacity, [the assignors] are effectively determining by whom, and under what circumstances gas will be transported" and are using the pipeline's facilities as if they were the assignors' facilities.[121] The Commission added that the NGA does not limit the Commission's jurisdiction to the actual physical transportation or delivery of natural gas and that a narrow construction of the Commission's jurisdiction would create a regulatory gap and a significant dilution of the Commission's regulatory authority over the pipelines themselves.

The Commission adheres to that analysis and conclusion that the Commission has NGA jurisdiction over the brokering or assignment of capacity by LDCs, and this is irrespective of whether the assignee is an LDC customer or, as Atlanta Gas maintains, a replacement shipper within the same state.[122]

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120. *Id.*, 48 FERC ¶ 61,248 at p. 61,873.

121. Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 at p. 61,452 (footnote omitted).

122. Accordingly, contrary to the United Distribution Companies (UDC)

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The Commission also believes that petitioners have not recognized the essence of a capacity assignment. In effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper. Both of those activities are subject to the Commission's jurisdiction under NGA sections 1(b) and 7(b) and (c).

The Commission agrees with the APGA that municipalities are beyond the jurisdiction of the Commission.[123] However, this means only that municipalities need not be certificated to transport gas on their own systems[124] or to participate in jurisdictional capacity brokering or releasing mechanisms.[125] However, this does not mean that municipalities are entitled to release capacity on an interstate pipeline without complying with the procedures pertinent to the pipeline's releasing mechanism. It means only that the municipalities need not be certificated to release capacity. The Commission's clarification in *Texas Eastern Transmission Corp*, that "all the conditions imposed upon program participants do not apply to municipalities" is not applicable where the conditions pertain to the mechanics of

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and New York PSC, the Commission's issuance of a limited certificate of public convenience and necessity to firm shippers, to the extent necessary and solely for the purpose of releasing firm capacity, 18 CFR 284.243(g), was appropriate.

123. Texas Gas Transmission Corp., 55 FERC ¶ 61,208 (1991); and Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 (1990). Nor are municipalities' rates and service regulated by most state Commissions.

124. Northwest Alabama Gas District, 42 FERC ¶ 61,371 (1988).

125. Texas Gas Transmission Corp., 55 FERC ¶ 61,208 at p. 61,698 (1991).

the release by and through the pipeline.[126] In that circumstance, the capacity releasing mechanism is no different from any other pipeline term or condition of service with which the municipality must comply.

2. Retention of Capacity Brokering

Several petitioners argue that the Commission should have allowed capacity brokering programs to continue[127] or, at least, grandfathered existing programs.[128]

NYSE&G argues that capacity brokering is more in tune with private contractual arrangements and is superior to prearranged deals under capacity releasing because the latter permits preemption by a "better offer," which is an "invitation to controversy."[129] The CNG LDCs argue that capacity brokering is superior because the LDCs "may temporarily broker capacity to their own end users."[130] Several petitioners argue retention of capacity brokering along side of capacity releasing will provide pipelines with the incentive to market released capacity, for example, in competition with their own interruptible

126. Texas Eastern, 51 FERC ¶ 61,170 at p. 61,454 (1990).

127. New York State Electric & Gas Corporation (NYSE&G), New Jersey Natural, CNG LDCs, Wisconsin Distributor Group, PSE&G, the Industrial Groups, and New York PSC.

128. CNG LDCs. Indiana Gas contends, without supporting argument, that "Order No. 636 should be amended to establish capacity brokering programs." Request for Rehearing at 7.

129. Petition at 7. "Best Offer" is discussed *infra*.

130. Petition at 5.

transportation.[131] New York PSC argues that capacity brokering should not be replaced because, under releasing, the pipelines are unnecessary middlemen and can underbid the LDCs to keep interruptible service. It also maintains that it is aware of no complaints against the programs on six pipelines serving New York State.

Atlanta Gas, New York PSC, UGI and CNG argue that the capacity releasing mechanism is too time consuming, too administratively complex, imposes additional transaction costs, and reduces flexibility. Hadson Gas Systems, Inc. (Hadson) similarly contends that the new capacity releasing rule will discourage the development of a secondary capacity market because the required posting of prearranged deals raises the possibility of deal stealing which will cause potential assignors to either fashion complicated, ambiguous, and confusing arrangements or just not attempt it at all.

The Commission upholds its decision not to approve new individually authorized capacity brokering and other capacity assignment certificates.[132] The Commission believes it is desirable for efficiency and administrative reasons for all allocations to be effected through the pipeline to avoid the possibility of discriminatory allocations. For example, the

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131. PSE&G and Wisconsin Distributor Group.

132. The Commission's decision to amend the terms and conditions of existing capacity brokering and other capacity assignment programs to conform to Order No. 636's capacity allocation mechanisms was effected in Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992). Hence, the Commission will address objections to that decision in the rehearing of that order and not here. That order will be issued contemporaneously with Order No. 636-A.

possibility exists that LDCs might favor their own end-users in ways that constitute potential undue discrimination. In addition, contrary to the rehearing contentions, the Commission believes that the two new generic capacity allocation mechanisms of sections 284.242 and 284.243 of the Commission's regulations are adequate substitutes for existing programs and will eliminate the potential for discrimination, while facilitating the development of the secondary transportation market.

The Commission believes that the mechanism for prearranged deals under the capacity releasing program will permit parties to fashion permanent or temporary capacity reallocations in a manner similar to capacity brokering. In that vein, as discussed below, the Commission is permitting releases for less than thirty days (up to 29 days) to be effected without prior posting on the EBB or bidding on the released capacity. Those releases must be announced on the EBB as soon as possible, but no later than forty-eight hours, after the transaction commences and no roll-overs or extensions are permitted without prior notice on the EBB and an opportunity to bid.

The opportunity for potential competitors to bid is appropriate because it permits someone to make a better offer and obtain the capacity. This may enable the releasing shipper to receive more revenue for its firm capacity. The posting of the prearranged deal is appropriate in order to keep all deals public so that discrimination can be detected and prevented. The pipelines are not unnecessary middlemen but perform the function of a public clearinghouse for all transactions. In addition, the EBBs should give releasing shippers exposure to more replacement shippers and pipelines will be able to combine releases to make then more marketable. The pipelines will have an adequate incentive to market released capacity because of the fee that they can receive to actively market capacity.

Moreover, as open access transporters, the pipelines must accommodate requests for service, if their own or released capacity is available. In addition, the pipelines must offer their own capacity on the EBB. The Commission views the competition between interruptible transportation and capacity releasing as part of a healthy secondary capacity market. The Commission does not believe that the lack of complaints on six pipeline systems is relevant to the devising of a generic capacity reallocation program for the entire pipeline industry.

As discussed further below, the Commission has adjusted the capacity reallocation mechanism to accommodate some of the arguments made by petitioners. However, the Commission has done that without compromising the central purpose of adopting the capacity allocation mechanism in lieu of capacity brokering — notice and oversight of the assignment of pipeline capacity. As modified, the Commission does not believe, based upon its experience with the gas industry, that capacity releasing will be too time consuming, too administratively complex, impose unreasonable costs, or unduly reduce flexibility. Rather, the Commission believes that an efficient, appropriately-priced capacity releasing mechanism can be fashioned to create an efficient, flexible, competitive, and reasonable secondary market for pipeline capacity while, at the same time, avoiding the potential for discrimination. Specific details of capacity releasing are discussed below in the section dealing with specific rehearing requests on those details.

3. Voluntary Reallocation Of Firm Transportation Capacity

Under new section 284.243, an open access pipeline must provide a capacity releasing mechanism that lets shippers voluntarily reallocate all or part of their firm transportation

capacity to any person. The capacity release mechanism would operate through the pipeline's electronic bulletin board, and the replacement shipper would contract with the pipeline for the reallocated capacity, with the releasing shipper receiving a credit for the proceeds of the release. Except when necessary to respond to petitioners' arguments below, the Commission will not repeat Order No. 636's discussion of the mechanics of capacity releasing.

a. Exceptions For Short Term Or Small Volume Transactions

Several petitioners contend that the Commission should not subject short-term (one to three months) or small volume transactions (less than 5,000 to 10,000 Dth) to the bidding requirements of the capacity release mechanism.[133] Instead, they contend the Commission should allow parties to consummate these transactions on their own, subject only to posting the deal on the pipeline's electronic bulletin board. They contend that the requirement for advance posting and bidding in Order No. 636 would be too administratively difficult for short term or low volume releases and therefore could inhibit the efficient allocation of capacity.

As a policy matter, the Commission believes that the public interest is served by fostering a robust secondary market in pipeline firm capacity. At the same time, the Commission seeks to ensure that the efficiencies of the secondary market are not frustrated by unduly discriminatory access to this market. To balance these objectives, the Commission will modify the

133. *E.g.*, United Distribution Companies, New York PSC, the Industrial Groups, Northern Distributor Group, New England Gas Distributor Group, Associated Gas Distributors (AGD), and ANR.

regulations to permit firm shippers to find their own replacement shippers and release capacity to those shippers for any period of less than one calendar month without having to comply with the bidding requirements of section 224.243. The same maximum rate would apply to these transactions as to other capacity release transactions. Releases under this exception must be posted on the electronic bulletin board as soon as possible, but no later than forty-eight hours, after the release transaction begins. Parties will be prohibited from rolling-over such agreements or granting extensions without complying with the requirements for prior notice and bidding.

The exception from the bidding requirements for short-term releases will not relieve the pipeline from its obligation to devise capacity releasing procedures facilitating short-term releases.[134] The Commission expects that, in most instances, capacity release mechanisms can be implemented which will permit releases for one day or less at any time during a month, and provide for release transactions to be finalized within twenty-four hours of posting. The Commission recognizes that meeting such goals may not immediately be achievable by all pipelines. Pipelines proposing significantly greater restrictions need to justify them and explain in their compliance filing when they will be able to adopt less restrictive conditions.

Accordingly, the Commission will modify section 224.243 to add a new paragraph (h) as follows:

(1) A release of capacity by a firm shipper

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134. Stock and commodity exchanges, for example, consummate such transactions in very short time periods and, with the availability of existing computer technology, pipelines can design workable short term releasing mechanisms.

to a replacement shipper for any period of less than one calendar month need not comply with the notification and bidding requirements of paragraphs (c) through (e) of this section. A release under this paragraph may not exceed the maximum rate. A firm release under this paragraph must be noticed on the pipeline's electronic bulletin board as soon as possible, but not later than forty-eight hours after the release transaction commences.

(2) A firm shipper may not rollover, extend, or in any way continue a release under this paragraph without complying with the requirements of paragraphs (c) through (e) of this section and may not re-release to the same replacement shipper under this paragraph until thirty days after the first release period has ended.

Given the modification for short term releases, the Commission does not find that a separate exception for low volume releases is needed. The short term modification will permit release of any amount of capacity for less than thirty days. Volumes of up to 10,000 Dth per day for more than this period may be significant and compliance with the notice and bidding requirements should not create any administrative difficulties.

b. Priority Issues

(1) Priority for Pre-Arranged Deals

The Commission in Order No. 636 established capacity releasing under section 284.243 as a nondiscriminatory vehicle for pipeline transportation customers to release capacity voluntarily on a permanent or temporary basis. In general, capacity would be released to the person offering the highest rate and offering to meet the other terms and conditions of the bid. The Commission recognized, however, that permitting parties to continue to prearrange deals for redistributing capacity would facilitate capacity reallocation. Permitting prearranged deals would provide pipeline customers with an incentive to market their unneeded capacity actively rather than simply posting the capacity on the pipeline's bulletin board. In section 284.243, the Commission therefore gave priority to prearranged deals: the replacement shipper under the prearranged deal would receive the capacity so long as it was willing to match any better offer. Several petitioners argue that the order of priority established in Order No. 636 should be modified.

Several petitioners argue that a releasing LDC should be able to designate replacement shippers without exposure to the bidding process.[135] They argue that such priority would ensure that the released capacity remains on the LDC's system, so that the LDCs would not lose revenues from the diversion of capacity to off-system markets. The Industrial Groups argue that, in the alternative, the Commission should permit releases to be conditioned on the replacement shipper using the released capacity to deliver gas to customers served by the releasing LDC.

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135. CNG LDCs, Alabama Gas Corporation (Alabama Gas), and the Industrial Groups.

Appendix C

American Paper Institute argues that existing end-use customers should have priority to released capacity if they are willing to bid the maximum rate. Peoples Natural Gas Company (Peoples Natural Gas) similarly argues that an end-user behind an LDC should have priority if it matches the price of a third party bidder even though it does not match other terms and conditions.

The Commission does not believe that revising its priority provisions for capacity release is necessary. The purposes of the capacity release provisions were twofold: first, to ensure that notice would be given for all capacity reallocations and second, to give parties an opportunity to bid a higher rate so that allocative efficiency is enhanced by allotting capacity to the shipper placing the highest value on the capacity. As discussed previously, the Commission is excepting short term releases from the bidding requirement. However, the Commission will not permit a general exception for all releases to a designated shipper. Such an exception would involve a large number of significant transactions and therefore would greatly undermine the allocative efficiency goal sought to be achieved by the bidding requirement. Elimination of the bidding requirement also is not necessary to enable LDCs and end-users to consummate beneficial deals to allocate capacity. Under the capacity release mechanism, an LDC can negotiate a prearranged deal with an end user and that end user will receive the capacity as long as it matches the best offer. Thus, an end-user under a prearranged deal meeting these conditions will be assured of receiving the capacity.

(2) Priority for Shippers on the Pipeline's Firm Queue

Brymore argues that the Commission's priority for

prearranged deals at the maximum rate is unfair to shippers that have been on a pipeline's queue for firm capacity, and that shippers on the firm queue should receive priority if they match the best bid. O & R Energy, Inc. (O & R Energy) asserts that, under certain Commission approved tariffs, parties have made transportation prepayments to hold a place in a pipeline's queue, payments which may be refundable if capacity is not available or the buyer withdraws its request. O & R Energy requests that the Commission modify section 284.243 to provide that the pipeline must first discharge its tariff obligations to potential shippers in its firm transportation queue.

The Commission does not believe shippers on a pipeline's firm queue should be accorded priority over prearranged deals. First, as pointed out above, the capacity release mechanism was not intended to prohibit prearranged deals, but to ensure that notice of all such deals was provided.[136] Second, the pipeline's queue applied only to the allocation of the pipeline's own capacity and never to released or brokered capacity. The Commission in Order No. 636 also modified the role of the firm queue by requiring that available pipeline firm capacity must be posted on the electronic bulletin board and allocated to the shipper making the best offer. In the restructuring proceedings, however, the parties should consider whether the existing firm queue or other provisions provide the best method for allocating the pipeline's available firm capacity when identically valued bids for pipeline capacity are received. The Commission will clarify that if a pipeline' firm queue is eliminated, deposits to retain position on the queue must be returned according to the terms of the pipeline's tariff.

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136. By requiring that capacity is to be awarded to the prearranged deal only when no better offer is received, the capacity release mechanism ensures that the capacity goes to the highest valued use.

Appendix C

(3) Priority for Sale of Pipeline Capacity

Order No. 636 did not adopt the NOPR's proposal that the pipeline may sell its own available firm capacity prior to reselling that of a releasing customer.[137] Instead, the pipeline must post its available firm capacity on the electronic bulletin board so that potential shippers can elect whether to purchase the pipeline's or releasing shippers' capacity. Some pipelines have requested the Commission to reinstate the provision allowing pipelines to sell unused capacity ahead of released capacity.[138] ANR and Tenneco, for example, argue that if released capacity is sold prior to pipeline capacity, the pipeline may be unable to sell its firm capacity, thereby raising transportation rates for all customers. They contend that customers unable to release capacity will therefore be paying higher rates which will subsidize customers that can release capacity.[139] CIG asks the Commission to permit pipelines to sell their interruptible capacity prior to the release of firm capacity arguing that otherwise, firm customers that cannot release capacity will not be able to mitigate the reservation fees they pay.

The Commission adheres to the requirement in Order No. 636 that pipeline capacity (firm and interruptible) must compete with released capacity. Competition between pipeline capacity and released capacity helps ensure that customers pay only the competitive price for the available capacity. Granting preferences to pipeline capacity over released capacity could interfere with

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137. Order No. 636 at p. 30,419.

138. *E.g.*, ANR, CIG, Tenneco, and Questar Pipeline Company (Questar).

139. Tenneco and ANR.

and frustrate competition and artificially raise the price of pipeline capacity to new shippers. Shippers seeking capacity should be able to select the transportation option (pipeline firm, released firm or pipeline interruptible) with the terms and price that best fits their needs. The pipelines are free to respond to releases of capacity as competition dictates, within the limits and requirements of the Commission's regulations.[140] Affording preference to pipeline capacity over released capacity also could reduce the incentive for shippers to post released capacity.

Further, the capacity release mechanism was intended to create a robust secondary market for pipeline capacity in which unneeded firm capacity would be available to shippers requiring that capacity. This allocation process should forestall the construction of unneeded new capacity, which in turn will result in lower costs for pipelines and all their firm shippers.

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140. The petitioners suggest that according pipeline capacity a preference over released capacity would result in reduced rates for all customers due to increased sale of pipeline capacity. However, any incremental sales of pipeline capacity would not affect the customers' rates in the short run. A pipeline's current rates are set in its tariff and generally are revised only when the pipeline files for new rates under section 4 of the Natural Gas Act. Thus, even if pipeline capacity was given the requested preference, the pipelines would retain the incremental revenues and would not have to reflect these revenues until an unspecified future date when the pipeline filed to raise its rates generally. In contrast, under the capacity release mechanism the releasing shipper immediately obtains a lower cost by receiving the proceeds from the release.

Appendix C

c. Terms and Conditions

(1) Determination of Best Bid

i. Should the Pipeline or Releasing Shippers Determine the Best Bid?

The Commission in Order No. 636 provided that releasing shippers can set the terms and conditions for the release of capacity and that the pipeline must allocate the released capacity to the person offering the highest rate, not over the maximum rate. Recognizing the multiplicity of releasing scenarios that could arise, the Commission determined that the parties in the restructuring proceedings should determine what constitutes the best offer.[141]

Several petitioners[142] request that the Commission clarify that the releasing shipper should be the appropriate party to determine the best offer, not the pipeline. Gas Company of New Mexico suggests that either the releasing shipper be given the ultimate decision to determine best offer or, alternatively, the choice "should be based on the total economic benefit provided to the releasing shipper." It posits that this approach would better deal with situations in which a releasing shipper may be releasing capacity on multiple pipelines. The Northern Distributor Group, Destec, and Fuel Managers Association request clarification that releasing shippers should be able to use criteria other than price

141. Order No. 636 at p. 30,418.

142. *E.g.*, United Distribution Companies, AGD, Long Island Lighting Company (LILCO), CNG LDCs, Wisconsin Distributor Group, UGI, Northern Distributor Group, the Industrial Groups, Destec, the Fuel Managers Association, Midland Cogeneration Venture (Midland Cogeneration), and the Pennsylvania Public Utility Commission (Pennsylvania PUC).

to choose replacement shippers. The Industrial Groups supports allowing releasing shippers to determine the best bid, but further argues that regardless of who decides, payment made by customers as part of their retail rates should be taken into account in determining the best bid. It argues that since customers of LDCs have been paying for pipeline capacity through their retail rates, they should not have to pay the effective maximum rate for released capacity.

On the other hand, some petitioners request that the Commission establish specific parameters for determining the best bid.[143] For instance, Spot Market Corporation of the State of Texas (Spot Market Corporation) is concerned about the operation of capacity release on the PGT system. It maintains that because PGT has a low transportation fee, every potential replacement shipper will bid the maximum amount and that a screen of factors must be used to establish priority.

The Commission will clarify its position with respect to terms and conditions and best bids. Due to the variety of releasing conditions that may exist, the Commission will not establish only one methodology for evaluating best bids, but will use the following approach.

The pipeline's tariff must include an objective and non-discriminatory economic standard for determining best bids. Releasing shippers may rely upon this standard in structuring their capacity releases, but are not required to do so. If a releasing

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143. National Independent Energy Producers (NIEP)(recommending objective generic standards such as net present value, first-come/first-served, or pro-rationing, but also giving weight to the opinion of the releasing shipper); Brymore (all other things being equal, *e.g.*, rate and term, the shipper guaranteeing the highest load factor usage should receive capacity).

shipper does not specify a standard, the standard in the pipeline's tariff will apply.

Releasing shippers may include in their offers to release capacity reasonable and non-discriminatory terms and conditions to accommodate individual release situations, including provisions for evaluating bids. All such terms and conditions applicable to the release must be posted on the pipeline's electronic bulletin board and must be objectively stated, applicable to all potential bidders, and non-discriminatory. For example, the terms and conditions could not favor one set of buyers, such as end users of an LDC, or grant price preferences or credits to certain buyers. The pipeline's tariff also must require that all terms and conditions included in offers to release capacity be objectively stated, applicable to all potential bidders, and non-discriminatory.

ii. Pooling and Aggregating Capacity

NIEP argues that the Commission's capacity release mechanism should permit pooling arrangements under which a replacement shipper obtains a pool of capacity rights on different pipelines from an LDC. The replacement shipper can use capacity from each pipeline and pays the LDC a weighted average price for the entire pool.

Based on NIEP's description, the average price term may in some instances appear to conflict with the regulations providing that the rate for released capacity cannot exceed a pipeline's maximum rate. As NIEP recognizes, the average price will be higher than the maximum rate on at least one pipeline. However, within the constraints of the regulations, the Commission intends for its capacity releasing program to be as flexible as possible in order to promote efficient releases. A

pooling arrangement, such as the one NIEP describes, potentially could be accomplished depending upon how the transaction is structured.

The APGA and Municipal Gas Authority of Georgia request that the Commission clarify that it will permit a program where firm capacity holders aggregate their unused firm capacity for release by the pipeline. They propose that the pipeline receive a commission of ten percent of all revenues, with the remainder credited to the firm capacity holders in proportion to the amounts of unutilized firm capacity that they made available.

The Commission finds nothing in the regulations promulgated by Order No. 636 that would prevent firm capacity holders from aggregating firm capacity on the same or different pipelines to enhance its marketability for release.[144] If more than one shipper is aggregating capacity, the shippers involved would have to determine among themselves how to allocate the credit from the release. The Commission further clarifies that the pipeline would be eligible to receive a negotiated marketing fee only if it actively markets the capacity.

iii. Length of Contract

American Paper Institute contends that the length of contract should not be taken into account in determining bid value,

144. In Order No. 636, the Commission gave an example of a shipper holding capacity from the Gulf of Mexico to New York being able to release its capacity between those points at up to the maximum rate for the path from the Gulf to New York. Order No. 636 at pp. 30,420-21. Similarly, a shipper holding capacity on an upstream and downstream pipeline, which together provide a path from the Gulf to New York, could aggregate that capacity for a single release. Each block of capacity could be sold at up to the maximum rate on each pipeline and the transaction would have to be posted on each pipeline's electronic bulletin board.

because not all gas users can commit to long term contracts. The Commission will not eliminate length of contract from the determination of best bid since a releasing shipper may consider contract duration to be an important consideration in releasing capacity.

(2) Creditworthiness

Several petitioners contend that the releasing party should have the right to condition its release on the replacement shipper demonstrating its creditworthiness or paying an amount in advance.[145] Because the replacement shipper is contracting with the pipeline for released capacity, it must satisfy all the pipeline's tariff provisions governing eligibility.[146] In the pipeline's restructuring proceedings, however, the pipelines need to develop tariff procedures to effectuate and expedite the capacity releasing mechanism. For example, pipelines may develop tariff provisions permitting bidders to pre-qualify under their eligibility standards.

(3) Peak Day Restrictions

Northern Illinois Gas Company (Northern Illinois Gas), *et al.*[147] is concerned about its ability to ensure that it has adequate gas volume flowing into its system on peak days. To deal with this problem, it asserts that, although replacement shippers generally should be able to make use of flexible delivery points,

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145. *E.g.* LILCO and New England Gas Distributors.

146. Order No. 636 at p. 30,419.

147. Peoples Gas Light and Coke Company, and North Shore Gas Company.

a releasing shipper should be able to restrict the replacement shipper's use of released capacity to primary delivery points either generally or in certain demand conditions. The Commission is not sure how restricting replacement shippers to primary delivery points would promote adequate gas flows on peak days since the gas flowing would be that of the replacement shipper. However, the Commission clarifies that a releasing shipper may include terms and conditions, such as recall rights, that will ensure it has adequate peak day transportation.[148] The Commission also notes that a party holding capacity to a primary delivery point always will have priority over a firm shipper using that delivery point as a secondary delivery point on an interruptible basis.

(4) Minimum Price

Western Resources, Inc. (Western Resources) asks for clarification that the releasing shipper may specify a minimum price. The Commission so clarifies.

(5) Consistency Of Release Conditions With Pipeline Tariff

ANR asks the Commission to clarify that any conditions and/or restrictions that may apply to the released capacity must be consistent with ANR's tariff and/or the original agreement between ANR and the releasing shipper. The Commission clarifies that all terms and conditions must not conflict with the pipeline's tariff, but notes that, under section 284.243(f), the pipeline may agree to release the releasing shipper from liability under its contract. In addition, of course, the releasing shipper

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148. *See* Order No. 636 at p. 30,418.

can establish additional terms and conditions specific to its release, such as providing for recall rights.[149]

(6) Other Preferential Terms And Conditions

The American Paper Institute is concerned that potential releasing shippers may attempt to add terms and conditions which will tie the release of capacity to other compensation paid to the releasing shipper, such as an LDC requiring the potential replacement shipper to pay a certain price for local gas transportation service or a producer conditioning the release of capacity on the purchase of the producer's gas. The American Paper Institute requests the Commission to clarify that such ties will not be permitted. Brymore is concerned about the possibility of abuse by releasing shippers favoring affiliates or requiring compensation outside of the reassignment process.

The Commission shares these concerns. The Commission reiterates that *all* terms and conditions for capacity release must be posted and nondiscriminatory, and must relate solely to the details of acquiring transportation on the interstate pipelines. Release of pipeline capacity cannot be tied to any other conditions. Moreover, the Commission will not tolerate deals undertaken to avoid the notice requirements of the regulations.

d. Releasing Rights Of Holders Of Upstream And Downstream Capacity

The Commission in Order No. 636 provided for flexible delivery points, in part, to achieve a broad and meaningful capacity releasing program. [150] The Commission provided that

149. Order No. 636 at p. 30,418.

150. Order No. 636 at p. 30,429.

such delivery points must be within the firm transportation capacity to which the shipper is entitled and, as an example, pointed out that a downstream LDC could deliver capacity upstream, but that an upstream LDC could not deliver gas downstream.[151]

Arizona Electric Power Cooperative, Inc. (Arizona Electric) argues that the Commission should not prevent a downstream replacement shipper from using an upstream shipper's capacity and adding additional downstream capacity to complete the journey. Arizona Direct Customers interprets the Commission's discussion as a prohibition on releases by upstream customers and contends that such a rigid interpretation should not prohibit "operational" releases on grid-like transmission networks where, it asserts, substantial deliveries are by displacement. Alabama Gas asks the Commission to modify Order No. 636 to provide that downstream shippers may not reallocate their capacity to shippers seeking upstream receipt points. It argues that permitting downstream shippers to release capacity upstream is unfair because the upstream shippers do not have the reciprocal ability to release capacity in the downstream market. Alternatively, it argues that whenever a downstream shipper releases capacity to an upstream shipper, the "hole" remaining from the unused downstream capacity should be reallocated to an upstream shipper so that it can release capacity further downstream.

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151. As the Commission pointed out, a shipper with transportation capacity from the Gulf of Mexico to New York City could release any transportation capacity between those two points, including transportation for a shorter haul. Order No. 636 at pp. 30,420-21. Thus, the releasing shipper could release capacity from the Gulf of Mexico to Atlanta to one replacement shipper and, if feasible, simultaneously release capacity from Atlanta to New York to a second replacement shipper (or use that capacity to transport its own gas).

Appendix C

The Commission's discussion in Order No. 636 provided an illustration of the point that a shipper can release only that capacity it has a right to use and for which it is paying. Thus, the capacity release mechanism treats all shippers equally. The upstream shipper can release only the transportation capacity it holds by paying a reservation fee and cannot release capacity that it has not reserved.[152] Upstream shippers can, of course, purchase downstream capacity and combine it with other capacity for delivery to downstream points. Ultimately, the determination of the capacity available for release on each pipeline must be determined in the individual restructuring proceedings based on the operational characteristics of each pipeline, including such factors as the availability of flexible delivery points. The Commission will not permit the reallocation of capacity between upstream and downstream shippers as proposed by Alabama Gas. Such a proposal is not only unduly complex, but it would deprive the downstream shipper of the ability to sell capacity which it has reserved by paying the reservation fee.

e. Rate Cap

The Commission's regulations provide that the pipeline must allocate released capacity to the shipper offering the highest rate, not over the maximum rate. [153] Several petitioners raise questions about the maximum rate for released capacity set by this provision.

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152. For example, a shipper paying a reservation fee for capacity from point A to point B could release only that capacity, because it has not paid a reservation fee for capacity beyond point B.

153. Section 284.243(e).

Appendix C

(1) Elimination Or Modification Of The Rate Ceiling

Tenneco and Northwest Pipeline Corporation (Northwest) argue that released capacity should not be subject to any price cap. They argue that removing the price cap will permit capacity to be allocated to the user placing the highest value on the capacity and will eliminate the need for determining an allocation method when more than one party bids the maximum rate. Northwest contends that any amounts received above the maximum rate should be shared between the releasing shipper and the pipeline. Alternatively, Tenneco suggests that the rate cap should be based on an estimate of the costs of constructing additional facilities that otherwise would be necessary if capacity was not released.

Based upon the information in this proceeding, the Commission will not remove the rate cap because the market for released capacity has not been established to be sufficiently competitive so that releasing shippers will not be able to exert market power.[154] Thus, the extent of competition in the secondary release market may not be sufficient to ensure that the rates for released capacity will be just and reasonable. The Commission will not permit any replacement shipper to pay more than the Commission established maximum just and reasonable rate for capacity.

Permitting pipelines to share in amounts received above the maximum rate, as Northwest proposes, could permit the pipeline to recover scarcity rents through the release program that it

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154. *See* Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486, 1510 (D.C. Cir. 1984) (market forces must be sufficient to hold rates to reasonable levels).

would not ordinarily receive. Northwest's revenue sharing approach might further create an incentive for a capacity constrained pipeline to withhold new construction because of the prospect of deriving additional revenues from the resale of capacity above the maximum rate. The Commission further will not permit the maximum rate for released capacity to be based on construction estimates, because such a rate could exceed the maximum tariff rate on file for the pipeline.

Western Resources requests clarification of the maximum rate provision, contending that the benchmark for released capacity should be the interruptible rate and that some pipelines may not offer interruptible transportation after the restructuring. The Commission will clarify that the maximum rate for released capacity is the maximum firm rate, not the interruptible rate. Under the capacity release provisions of section 284.243, a customer is releasing firm capacity. The replacement shipper pays the pipeline both the usage rate and the reservation fee determined by the bidding process (up to the maximum rate). The releasing shipper then receives a credit for the reservation fee paid by the replacement shipper.[155]

(2) Items Included in Determining the Maximum Rate

Two petitioners raise questions about the items included in

155. The releasing shipper receives a credit toward its reservation fee because it pays this fee monthly to reserve capacity on the pipeline and the replacement shipper is acquiring the ability to use this reserved capacity. The releasing shipper does not receive a credit related to the usage fee because it has not paid the usage fee in advance. The usage charge reflects the pipeline's variable cost and is paid on the volume of gas actually shipped. After the release of capacity, the replacement shipper, not the releasing shipper, is the party shipping gas and therefore the replacement shipper is responsible for paying the usage charge to the pipeline.

the rate cap and about the treatment of refunds. AGD asks whether the rate cap includes all surcharges applicable to the capacity (e.g. transition costs and GRI charges) and the administrative fee and the revenue-sharing amount ("incentive fee"). Phillips Petroleum Company, Phillips Gas Marketing Company and GPM Gas Corporation (Phillips) argue that replacement shippers should share in refunds if the replacement shipper is paying more than the ultimately determined just and reasonable rate. The Commission agrees that the cap should include all fees paid by the releasing shipper, which would include surcharges and transition costs, and that replacement shippers can, in appropriate circumstances, share in refunds if their rate exceeds the just and reasonable rate ultimately determined.

But the Commission does not agree that the capacity can be resold at a rate including the pipeline marketing fee.[156] The marketing fee is not part of the cost of the transportation being released and the replacement shipper should not pay more than the maximum transportation rate for the capacity it is acquiring. The marketing fee represents the cost of finding a replacement shipper and therefore the releasing shipper should pay this fee, since it is the one marketing the capacity.

(3) Incremental Rates

Midland Cogeneration and Southern California Edison Company (SoCal Edison) raise issues regarding the application of the capacity release mechanism to pipelines with incremental or "vintaged" rate structures and Midland Cogeneration requests

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156. As discussed later, the Commission is no longer permitting pipelines to recover the costs of operating the capacity release mechanism through an administrative fee.

a technical conference on this issue. Midland Cogeneration contends that under vintage pricing rate schedules, incremental customers will effectively be shut out from participating in the capacity releasing because they are competing to release capacity with rolled-in customers paying a much lower rate. It asserts that the incremental customer therefore will not be able to mitigate its capacity costs while rolled-in customers will have excellent prospects of recovering all their capacity costs. Midland Cogeneration and SoCal Edison put forward a number of solutions to this problem, including revenue pooling, granting priority to incremental releases, and establishing a single price floor based on the incremental rate or an average rate.

The Commission cannot and will not make a generic determination on the various methodologies proposed by Midland Cogeneration and SoCal Edison since resolution of such issues may depend on the characteristics of the pipeline and the services it offers. The parties in restructuring proceedings involving incremental rates should consider and propose methodologies to ensure that the capacity release mechanism operates efficiently and that all parties are treated fairly and equitably, without undue discrimination.

f. Credits To Releasing Shippers

(1) Credits Exceeding Reservation Fee

In section 284.243 (f), the Commission provided that releasing shippers will receive a credit towards their reservation fee for the proceeds of any release. A number of petitioners have raised the issue of whether releasing shippers can retain revenues exceeding their reservation fee if they pay discounted rates. Western Resources asks the Commission to clarify that if the rate paid by the replacement shipper is greater than the rate

paid by the releasing shipper, the capacity holder should receive a credit for the release revenues and thereby receive the benefit of its bargain in gaining a long-term discounted rate. On the other hand, ANR argues that if the net revenues from the release exceed the releasing shipper's reservation fee, the pipeline should retain the incremental revenues, because that is consistent with the Commission's intent to allow the marketplace to set the price of services and would prevent overcontracting for firm capacity. Northern Natural Gas Company (Northern Natural) contends that the Commission should not permit discounted firm transportation to be released. It contends that the pipeline entered into those contracts based on the needs of the customer and the particular competitive situation with respect to end use markets and suppliers and that it would be inequitable for the discounted shipper to release that capacity. CIG asks that pipelines be allowed to address, in their restructuring proceedings, whether and to what extent capacity releasing shippers must share their revenue with other system users.

The Commission clarifies that a releasing shipper paying discounted rates is entitled to receive proceeds from a release even if such proceeds exceed its reservation fee. This ensures that shippers holding capacity have the incentive to release that capacity when others place a higher value on the capacity than the capacity holders do. The Commission will not limit competition by exempting discounted fixed-rate firm contracts from the capacity release mechanism nor will it permit the pipeline to retain incremental proceeds. Since the pipeline is not releasing the capacity, no efficiency or other procompetitive goal would be furthered by allowing it to retain incremental proceeds. If shippers holding discounted transportation are permitted to release that capacity, the pipeline is no worse off; the pipeline still receives the same total reservation charge for which it contracted with the releasing shipper.

(2) Credits For Capacity Not Sold

Brooklyn Union suggests that, even if released capacity of one month or more is not resold, the pipelines should credit the releasing shipper with an amount based on the pipeline's return on equity and related taxes. It argues that its proposal would provide pipelines with an incentive to maximize throughput by placing pipelines at risk for the same proportion of fixed costs as the MFV rate methodology and would therefore obviate the need to mitigate costs in connection with SFV rates. The Commission rejects this proposal. Under the releasing mechanism, the pipeline should not be at risk for selling capacity held by shippers; the releasing shippers have contracted for the capacity and therefore they should bear the risk if the capacity cannot be resold.

g. Effect Of Capacity Release On Interruptible Transportation

(1) Requirement To Provide Interruptible Transportation

American Paper Institute claims that one pipeline proposed to discontinue offering interruptible transportation based on Order No. 636 and requests the Commission to clarify that pipelines will still be required to provide interruptible transportation after implementation of Order No. 636. Section 284.9 of the Commission regulations specifically requires that interstate pipelines must "offer transportation service on an interruptible basis."

Appendix C

(2) Contribution Of Interruptible Transportation To Recovery Of Fixed Costs

A number of petitioners raise questions about the cost allocation and revenue responsibility to be assigned to interruptible transportation after capacity release has been implemented.[157] They point out that the Commission's traditional approach has required that interruptible transportation customers contribute to the recovery of the pipeline's fixed costs based on an estimated volume of interruptible transportation. However, they contend that once capacity release is implemented, interruptible transportation will face competition from released capacity and that estimating the volume of interruptible transportation that will be sold, and its rate, will be exceedingly difficult, particularly since the parties have no prior experience with a capacity release program. Some petitioners contend that if fixed costs remain in interruptible rates and interruptible volume or average interruptible rates decrease, the pipeline may not be able to recover the costs assigned to interruptible transportation.[158]

Some of these petitioners propose that the Commission depart from its previous practice of projecting interruptible volume and revenues and instead set firm rates without considering interruptible transportation.[159] If the pipeline is able to market interruptible transportation, the pipeline would then have to credit such revenues to the firm capacity holders. They

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157. *E.g.*, Northwest, Western Resources, Questar, NIEP, APGA, New Jersey Natural, Municipal Gas Authority of Georgia, and INGAA.

158. Questar and INGAA.

159. Northwest, Western Resources, NIEP, and APGA.

propose, to provide the pipeline with an incentive to market interruptible transportation, the pipeline would retain a portion of the proceeds as a marketing fee.[160]

In Order No. 636, the Commission did not address the manner in which fixed costs should be allocated to interruptible service. However, the Commission recognizes that the implementation of capacity release mechanisms and the potential use of seasonal contract entitlements, discussed below, may affect the level of interruptible transportation and that the throughput mix between firm and interruptible services, therefore, will have to be considered by the parties in the restructuring proceedings.[161] The parties to the restructuring proceedings may agree upon an appropriate allocation of throughput and cost to interruptible transportation. However, when the amount of interruptible transportation is uncertain, the parties should consider some type of a revenue crediting mechanism.[162]

As an example of this potential approach, the pipeline and its firm shippers might decide to attribute no revenue

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160. The American Paper Institute contends that the pipelines need incentives to continue to market interruptible transportation and proposes a revenue crediting approach. On the other hand, Michigan Gas Utilities Division of Utilicorp United Inc. (Michigan Gas) proposes a revenue sharing approach intended to mitigate the pipeline's incentive to prefer its own interruptible capacity over released capacity.

161. *See e.g.*, Columbia Gas Transmission Corp., 59 FERC ¶ 61,261 (1992); Stingray Pipeline Company, 59 FERC ¶ 61,372 (1992).

162. *See* Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, at 62,057 n.49 (1989) (benefit sharing possible solution to difficulty of estimating amount of discounting).

responsibility to interruptible transportation.[163] Since the pipeline's firm shippers would be responsible for all pipeline costs, revenues from the sale of interruptible transportation would be credited to the firm shippers.[164] Under this potential approach, the parties to the restructuring proceedings also may consider whether other methods are needed so that the pipeline would not have an incentive to favor the sale of either interruptible or released capacity over the other service.

(3) Pipeline Preferences

Several petitioners are concerned about the pipelines giving preference to their own interruptible or repackaged capacity over released capacity and some have requested that the Commission either establish specific remedies for pipeline abuse or require the staffing and facilities for capacity release to be separate from the transportation and gas marketing personnel and facilities.[165] Michigan Gas and New Jersey Natural contend that the pipelines have an inherent advantage in selling interruptible capacity, because the releasing mechanism may not make time-sensitive releases possible and the pipelines may offer an interruptible rate lower than a posted release rate, thereby inducing potential replacement shippers to refrain from bidding for the posted

163. The pipeline's maximum interruptible rate would be derived from the firm rate, such as by converting the maximum firm rate into a daily rate.

164. A full credit of all interruptible revenues to firm shippers may not be appropriate if the pipeline has some revenue and cost responsibility (such as GSR costs) allocated to interruptible transportation.

165. NASUCA, Fuel Managers Association, Public Utilities Commission of the State of California (CPUC) (requesting specific remedies if pipelines seek to thwart the release process), and UGI (separation of personnel).

released capacity in the expectation that they could obtain interruptible transportation more cheaply.

The Commission in Order No. 636 has provided, in section 284.8 (b)(2) & (3), that pipelines cannot discriminate between released capacity and the pipeline's unsubscribed firm or interruptible capacity. The Commission sought to prevent attempts to circumvent or thwart the process by setting forth specific parameters to govern the capacity release mechanism. For example, the pipeline is *required* to post all capacity and contract with replacement shippers offering the best bid. In addition, the pipelines should design their restructuring proposals in a way that does not provide them with the financial incentive to favor the sale of their interruptible transportation (or their own repackaged capacity) over the sale of released firm capacity by other shippers.

As a further effort to eliminate requirements that might provide pipeline interruptible transportation with advantages over released firm capacity, the Commission is revising its position on the pipelines' collection of the administrative fee for operating the capacity release mechanism. As discussed below, the Commission is no longer permitting the pipelines to recover the costs of operating the capacity releasing mechanism through a separately stated administrative fee. The pipeline will recover these costs in its rates as part of its cost of service.

At this point, therefore, the Commission sees no necessity to provide for further control over the process, such as requiring further separation of functions or devising specific penalties for pipeline abuse. The Commission also does not believe any changes in the capacity release program are necessary to address the concerns of Michigan Gas about short-term releases or the ability of pipelines to undercut rates for released firm capacity.

First, as discussed previously, the Commission is modifying its regulations to ensure that short-term releases can take place by exempting releases of less than thirty (30) days from the bidding requirements of the rule. Second, as discussed above, the Commission will examine restructuring proposals to ensure that the pipelines do not have financial incentives to favor the sale of interruptible transportation over released capacity. Moreover, under the capacity release program, a releasing shipper can design its release with no minimum price term. Thus, the pipeline would not know the final bid rate in advance so that it could undercut that rate. Additionally, a potential replacement shipper that waits for the availability of interruptible transportation is taking a risk that another customer will acquire the released firm capacity, so that interruptible transportation is no longer available.

h. Administrative Issues

(1) Administrative Fee

In Order No. 636, the Commission stated that the pipelines could charge a reasonable administrative fee to cover their out of pocket expenses in connection with establishing and operating capacity releasing programs. It also provided that the pipelines could share in the proceeds of a release when the pipelines take affirmative action to market the released capacity and find the replacement shipper.[166] A number of petitioners request the Commission to clarify various items relating to the administrative fee. They assert that the pipeline should not be able to recover excessive revenues from the administrative fee,[167]

166. Order No. 636 at pp. 30,419-20.

167. United Distribution Companies, State of Michigan and Michigan (Cont'd)

the fee should be separately stated,[168] the pipeline should return the administrative fee when it allocates its own capacity,[169] and the pipeline should only be able to share in proceeds when it finds a replacement shipper.[170]

As discussed previously, the Commission will no longer permit the pipelines to recover their costs for operating the capacity release program through a separately stated administrative fee in order to eliminate any potential advantages that interruptible transportation may enjoy relative to released capacity. The pipeline should recover the fixed costs for establishing the bulletin board in its transportation rates as part of its cost of service.[171] The Commission will clarify that the pipeline may receive a marketing fee when the releasing shipper reaches an agreement with the pipeline to actively market its capacity.

(2) Relationship Between Releasing And Replacement Shippers

Section 284.243(f) provides that the releasing shipper

(Cont'd)
Public Service Commission (State of Michigan), and the Iowa, Missouri, and Wisconsin State Commissions.

168. INGAA.

169. State of Michigan.

170. United Distribution Companies.

171. The pipeline also could charge a fee to parties using the bulletin board that reflects the variable cost of such use (*e.g.* EBB staff, monthly
(Cont'd)

remains liable under its contract with the pipeline unless the pipeline releases it from its contract. The State of Michigan argues that since the replacement shipper must meet all of the pipeline's tariff provisions, the releasing shipper should not remain liable on the contract. Two petitioners request clarification of whether the releasing or replacement shipper ultimately is responsible for certain fees and charges, such as imbalance penalties and overrun charges.[172] Northern Illinois Gas argues that the capacity reallocation program "should automatically establish privity between the assignor and assignees so that the assignor can sue in the event it is billed by a pipeline for service provided to the assignee."

Due to the variety of possible releasing scenarios, the Commission believes that, unless the pipeline agrees otherwise, the releasing shipper must remain liable on its contract with the pipeline for payment of the reservation fee. The Commission will clarify, however, that the releasing shipper should not be responsible ultimately for penalties or other charges incurred by the replacement shipper. These charges are unrelated to the reservation of capacity and primarily are designed to deter shippers from engaging in certain prohibited conduct. No purpose would be served by requiring the releasing shipper to be responsible for these charges, since after the capacity release, it has no control over the conduct of the replacement shipper. The Commission will not establish contractual privity between the releasing and replacement shippers. The releasing shipper's

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telephone line charge, maintenance). This fee would ensure that those using the bulletin board more frequently, such as marketers, would be charged an amount relating to their use of the board and that their use would not be subsidized by infrequent users.

172. LILCO and ANR.

right to be subrogated to the pipeline's claim is a matter to be determined by law and the contract between the releasing shipper and the pipeline.

(3) Posting Of Offers To Purchase Capacity

Rochester Gas suggests that the Commission require pipelines to post on their electronic bulletin board offers to assume or purchase capacity. The Commission believes that this suggestion should be adopted in order to facilitate communication between buyers and sellers. Accordingly, the Commission will amend section 284.243(d) to require the pipelines to post offers to purchase capacity. In this situation, the shipper seeking capacity would have to pay any posting fee required.[173]

(4) Individually Certificated Transportation

In Order No. 636, the Commission stated that individually certificated non-part 284 transportation arrangements can be released under section 284.243 [174], but did not include this provision in section 284.243. Several petitioners[175] seek clarification that individually certificated transportation can be released or ask that section 284.243 be amended to conform to Order No 636's text. On reconsideration, the Commission has

173. Of course, if the offer to purchase resulted in an agreement to assign capacity, that agreement would be subject to the bidding requirements of the rule.

174. Order No. 636 at p. 30,418.

175. *E.g.*, Philadelphia Electric Company (Philadelphia Electric), LILCO, Northeast Energy Associates and New Jersey Energy Associates (Northeast Energy), New England Power Company (New England Power), SoCal Edison, and Questar.

determined that holders of individually certificated transportation under Part 157 should not be able to release capacity under the capacity release mechanism of Part 284, since they are not governed by Part 284 or affected by the provisions of Order No. 636 which revised the Part 284 regulations. Accordingly, the Commission will not amend section 284.243. Holders of individually certificated transportation may convert to Part 284 transportation if they wish to release capacity.

(5) Pregranted Abandonment

Under section 284.243 (b) and (f), a shipper can release its capacity permanently and, if the pipeline agrees to cancel its contract, the shipper will no longer be liable to the pipeline for reservation fees for that capacity. Texas Gas requests that, in this situation, the Commission clarify that the pipeline has pregranted abandonment authority to cease firm transportation to the releasing shipper. The Commission will clarify that pregranted abandonment applies. Section 284.221 (d) provides for pre-granted abandonment upon the "termination of each individual transportation arrangement . . . ."

4. Order No. 636 - Upstream Pipeline Capacity

New § 284.242 promulgated by the Commission in Order No. 636 provides that an open access upstream pipeline must permit a downstream pipeline to assign its firm transportation (including storage) capacity (whether Part 284 or individually certificated) on the upstream pipeline to the downstream pipeline's firm shippers, and that a downstream pipeline must assign its upstream firm transportation (including storage) capacity (whether Part 284 or individually certificated) to its firm transportation customers to the extent necessary to provide capacity to those shippers that desire upstream capacity.

Appendix C

a. Retention of Upstream Capacity by Pipelines

Tenneco, CNG, Southern Natural Gas Company (Southern), and Carnegie argue that pipelines should be permitted to retain upstream pipeline capacity to perform their merchant role, to avoid transition costs associated with buying out upstream supply contracts, or to perform their no-notice transportation. CNG points out that Order No. 636 permits pipelines to retain a share of storage upstream of the place of unbundling. CNG argues that it is likewise necessary for pipelines to retain a share of pipeline capacity upstream of the place unbundling to avoid a severe competitive disadvantage.[176] Southern also argues that the Commission "has not identified any evidence to support its determination that retention of upstream capacity has prevented other parties from gaining access to upstream supplies."

Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company (Columbia) argues that "[t]he Commission should permit pipelines to negotiate and file a different nondiscriminatory proposal for treatment of upstream capacity if it can demonstrate that the result is superior to mandatory assignment and that the Commission's goals are achieved."[177] In particular, Columbia argues that the Commission should "recognize that mandatory assignment of 'market delivery' contracts may not yield the best result on some pipeline systems."[178] Columbia asserts that those contracts are needed to

176. See also Texas Gas' argument that upstream pipeline capacity needed to serve existing pipeline purchase contracts for gas to be resold on an unbundled basis should be grandfathered. CNG and Texas Gas are referring to unbundled sales downstream of the product area.

177. Petition at 26.

178. *Id.*

avoid losing throughput.[179]

The Commission's intent is to afford gas purchasers the opportunity to purchase gas in the production area.[180] Capacity held by downstream pipelines on upstream pipelines is one limiting factor on the downstream pipeline's customers' ability to buy gas in the production area reached by the upstream pipeline. However, the Commission will permit upstream pipelines to retain production area capacity rights upstream of the place of unbundling, but only to the extent the pipelines need those rights in order to make their unbundled sales at their place of unbundling.[181] For example, if an upstream pipeline's unbundling point is at its mainline connection to a production area, it can retain capacity on laterals upstream of the unbundling point, if they are needed for the upstream pipeline to have an adequate opportunity to make unbundled sales at the unbundling point. The allocation of production area capacity upstream of the place of unbundling among the upstream pipeline and others seeking capacity must be done on a nondiscriminatory basis and the costs associated with the upstream capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate.

The Commission will also permit downstream pipelines to

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179. Columbia describes "market delivery" contracts as "contracts under which gas is transported from gas supply areas to various locations throughout Columbia Transmission's system." *Id.*

180. Columbia's request for an exception for "internal capacity" contracts is discussed *infra*.

181. This is in addition to production area capacity needed for operational management and balancing and "no-notice" transportation.

retain some upstream pipeline capacity that is downstream of the place of unbundling on the upstream pipeline, but only to the extent such capacity is demonstrated by the downstream pipeline to be necessary for operational management and balancing purposes and the performance of the no-notice transportation service. For example, a downstream pipeline not connected to a production area but connected to an upstream pipeline (*e.g.*, Alabama-Tennessee Natural Gas Company (Alabama-Tennessee) and Tennessee Gas Pipeline Company) can retain capacity on the upstream pipeline to ensure that it has access to gas to keep its line pack in balance. However, the Commission will not permit a downstream pipeline to retain transportation or storage capacity on upstream pipelines to perform a sales service at the interconnection with an upstream pipeline. This is necessary to ensure that pipeline sales occur as far upstream on the pipeline grid as possible.

Nothing in this rule is intended to prohibit a transportation customer from contracting with a pipeline to act as its agent in nominating, scheduling, or otherwise managing its activities on the upstream pipeline, provided that the customer retains title to the capacity.

b. Upstream Supply Contracts

As stated above, the Commission is concerned about pipeline obligations under upstream supply contracts and has included costs incurred in connection with those contracts as transition costs to be recovered by the pipelines.[182]

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182. Texas Gas' argument that it should be relieved of its purchase obligation under stranded gas purchase contracts stemming from the assignment of upstream pipeline capacity is discussed, *infra*.

Tenneco argues that to reduce transition costs, "the Commission should require customers taking assignment of the upstream pipeline capacity, to take along with it an assignment of an equivalent amount of supply from the downstream pipeline's current suppliers."[183]

Northern Illinois Gas argues that "pipelines should be allowed to give priority to customers who will take the gas supplies associated with Account No. 858 capacity or who will purchase the inventory associated with the upstream storage."[184] Northern Illinois Gas would limit this conditioning of assignment to the restructuring proceeding but supports it then to reduce *transition* costs.

Similarly, Atlanta Gas argues that upstream pipeline capacity dedicated to a particular customer's certificated service should be allocated to that customer.

The Commission will not require downstream pipeline customers to take upstream supply along with upstream capacity. While that could limit transition costs, it would unfairly limit gas purchasers in their choice of gas merchants and, therefore, would be unduly anticompetitive. But the Commission encourages parties to voluntarily arrange assignments to minimize transition costs. Hence, Atlanta Gas' more general request is denied.

c. Length of Upstream Pipeline Assignments

Order No. 636 provided that upstream capacity assignments

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183. Petition at 13.

184. Petition at 29.

under section 284.242 are permanent. CIG asks that the Commission make it clear that the shipper acquiring that capacity does not obtain any extension rights (such as under an evergreen clause) except for the right of first refusal when the original agreement terminates.

The Commission disagrees with CIG. The Commission sees no reason why the downstream pipeline's evergreen rights should not be assigned to downstream customers under section 284.242. The downstream customer should stand in the shoes of the downstream pipeline, if the assignment occurs.

d. Abandonment

Texas Gas asks the Commission to provide for pregranted abandonment of the upstream pipeline's service obligation to the downstream pipeline with respect to the capacity assigned to downstream customers under section 284.242. The Commission clarifies such abandonment applies. The assignment is permanent and therefore terminates the contractual arrangement between the upstream and downstream pipeline. Section 284. 221(d) provides for pregranted abandonment upon the "termination of each individual transportation arrangement. . . ."

e. Relationship of Section 284.242 to Restructuring

Order No. 636 prevents the downstream pipeline from giving up upstream capacity in the restructuring proceeding except under 18 CFR 284.242. Northern Illinois Gas requests that the Commission permit those releases with the written consent of the participants in the downstream pipeline's

restructuring proceeding of an upstream pipeline.[185]

The Commission's concern was that customers of downstream pipelines have priority access to upstream transportation and storage capacity during the restructuring proceedings.[186] The Commission, therefore, will permit downstream pipelines to relinquish upstream capacity during the restructuring proceedings (see *infra* on restructuring relinquishment), if all of its downstream pipeline's customers consent to the relinquishment and there is someone willing to take the upstream capacity.[187] For example, with that consent, a downstream pipeline could give up upstream capacity under the mechanism established for capacity adjustments in the restructuring proceeding under 18 CFR 284.14 (e).

f. Use of Upstream Capacity

CIG asks for clarification that the assigned or released upstream capacity be subject to the receipt and delivery points specified in the existing contracts to prevent sales customers of downstream pipelines from fundamentally changing the use of the capacity. Similarly, Columbia maintains that the Commission

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185. See also National Fuel Gas Supply Corporation (National Fuel) — pursuit of upstream capacity reduction after notice and receipt of no objections.

186. However, this priority does not extend to customers of customers of downstream pipelines.

187. Brymore requests clarification that the upstream pipeline assignment policy of section 284.242 is to be a public process during the restructuring proceedings which upstream capacity is assigned in a nondiscriminatory basis and is not a "trading chip." The Commission so clarifies.

failed to consider the relationship among permanent assignment of upstream capacity, flexible delivery points, and its ability to deliver market requirements through the changed delivery point.

As stated above, the downstream pipeline is entitled to retain some upstream capacity below the upstream pipeline's point of unbundling, only if it demonstrates that it is needed for operational management and balancing and no-notice transportation purposes. In that light, the Commission sees no reason why assignees of capacity cannot change receipt and delivery points under the Commission's flexible receipt and delivery point policy, including changing primary points if firm capacity is available. Of course, the assignee must comply with the operational terms and conditions of the pipeline's tariff.

g. Exemptions

In Order No. 636, the Commission exempted certain arrangements from section 284.242's requirements with respect to the assignment of upstream capacity, specifically, to interruptible capacity held by downstream pipelines on upstream pipelines, firm capacity held by downstream pipelines on intrastate pipelines, and upstream exchange transactions.[188]

Baltimore Gas and Electric Company (BG&E) argues that the exemption is too broad and asks the Commission to clarify that "the exemption of firm capacity held by downstream pipelines on intrastate pipelines and upstream exchange transactions was not intended to apply to any such capacity that had been used in the past to support any service."[189]

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188. Order No. 636 at p. 30,418.

189. Petition at 7.

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Mobil argues that while there may be exchanges necessary to pipeline operations or no-notice service, this issue should be resolved in the restructuring proceedings where the pipeline should justify the retention of exchanges.

Columbia maintains that the Commission should except "internal capacity" contracts where it delivers gas to the upstream pipeline and the upstream pipeline redelivers the gas back to Columbia at another point in its system. Columbia argues that these "internal capacity" contracts are analogous to exchanges and are needed to meet its delivery obligations without building new pipelines.

The Commission has no authority, in general, to order intrastate pipelines to permit the relinquishment of capacity used for intrastate services by their shippers to downstream customers. Accordingly, the Commission did not intend to subject Subpart C (intrastate) pipelines to section 284.242. The Commission encourages intrastate pipelines to participate in the restructuring proceedings and to voluntarily consent to any reassignment proposal in a restructuring proceeding on terms and conditions acceptable to it. This may be especially appropriate if the intrastate capacity, as suggested by BG&E, is needed to support service to a particular customer of the interstate pipeline. If a person believes that this is necessary in a specific case with respect to Subpart C capacity, it may petition the Commission to take appropriate action.

The Commission will continue to except exchanges and analogous transactions. Whether Columbia's "internal capacity" contracts qualify for such treatment is an issue for the restructuring proceeding. Those arrangements are too diverse and complex to be subject to a rule designed for upstream

pipeline capacity. However, as stated above, the downstream pipeline needs those arrangements only for operational management and balancing and no-notice transportation purposes. In addition, the Commission will not tolerate retention of exchanges and similar arrangements to force downstream sales customers to remain pipeline sales customers.

h. Application to Individually Certificated Service

Section 284.242 requires open access pipelines to permit the assignment of upstream pipeline capacity to customers of downstream pipelines. Questar observes that the text of Order No. 636 provides that individually certificated firm transportation (including storage) is subject to section 284.242, but that section 284.242 does not so provide. The Commission is amending section 284.242 to conform to the text of Order No. 636.

5. Buy/Sell Arrangements

As stated above, the Commission prohibited buy/sell arrangements once the pipeline's capacity releasing program is effective, but grandfathered such arrangements existing on that date provided they are posted on the electronic bulletin board for informational purposes. Most buy-sell issues will be considered in the rehearing order in *El Paso Natural Gas Co.*, which dealt with certain existing buy-sell arrangements.[190] Here, the Commission will discuss only those issues raised with respect to continuation of existing buy-sell arrangements and posting on the electronic bulletin board.

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190. 59 FERC ¶ 61,031 (1992). *E.g.*, the Commission's jurisdiction over buy-sell arrangements will be addressed in the order on rehearing, which is being issued contemporaneously with this order.

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Cascade Natural Gas Corporation, the Washington Water Power Company (Cascade), and NIEP ask the Commission to confirm in the regulations that buy-sell arrangements survive as stated in the text of Order No. 636 and that surviving buy-sell arrangements continue through any evergreen or rollover period in the buy-sell contract or at least until existing financing arrangements for underlying IPP projects expire.

SoCal Edison states that it is concerned that an existing capacity holder may release capacity involving a buy-sell agreement and that the buy-sell party "may be temporarily without authorization to continue its transportation service pending the ability to retain the capacity (in its own name) as part of the pipeline's capacity releasing program".[191] It asks the Commission to clarify that the party using the grandfathered capacity will be allowed to continue to use it through and until that party decides whether to retain the capacity (in its own name) under the pipeline's capacity releasing program.

NIEP states that some buy-sell arrangements involve the pooling of capacity rights on several pipelines. They ask the Commission to clarify that "buy-sell pooling arrangements are valid and should be grandfathered under the Final Rule" and suggest that "an LDC, participating in an existing buy/sell program or a pre-arranged deal, may simply pro rate the amount of buy/sell or pre-arranged capacity pooled among all of the relevant pipelines, so that every pipeline may post such a pro rated amount on its bulletin board for informational or capacity reservation purposes, subject to change from time to time [or] . . . the LDC could notify its pipeline transporters of the pooling arrangements without attributing any specific buy/sell or pre-arranged volumes to any particular pipeline and simply indicate

191. Petition at 11.

that part of the LDC's reserved capacity will be used for that purpose."[192] They also ask the Commission to revise the rule to permit the buy/sell customers to pay the weighted average rates of the pipelines.

The Indicated Shippers argue that buy/sell arrangements should be terminated as of the date of the *El Paso* order or the date a capacity release program is instituted or should be subject to the "better offer" rule.

Generally, the Commission denies rehearing on these issues. The Commission will permit all grandfathered buy/sell arrangements to continue pursuant to their terms, including evergreen provisions in the contract in effect on the date of posting on the electronic bulletin board. This will permit the parties to those arrangements to receive the benefits of their bargain. The Commission observes that revised section 284.243(d) requires the pipeline to post offers to purchase capacity. Thus, customers receiving service under a grandfathered buy/sell transaction can use this provision to locate other capacity holders willing to offer a better deal.

The Commission clarifies that existing buy/sell pooling transactions such as that described by NIEP may be grandfathered. This should be done by posting the complete details of the pooling arrangement on the EBB of each pipeline involved in the pooling of capacity.

Marathon Oil Company (Marathon) argues that the grandfathering of buy/sell arrangements creates an erroneous disparity *vis a vis* sales to pipelines. It argues buy/sell deals should be phased-out. As of the effective date of the pipelines'

192. Petition at 6.

compliance with Order No. 636, no new buy/sell arrangements can be consummated. The Commission believes this balances all interests involved and provides a suitable transition to the Order No. 636 release program.

The Commission views the problem raised by SoCal Edison as a misunderstanding of releasing. While the LDC releases the capacity for resale, it does not lose its right to use that capacity until the replacement shipper has the right to use that capacity.

The Commission rejects Indicated Shippers' requests that grandfathered buy/sell arrangements be terminated. The Commission believes that the parties to existing buy/sell arrangements should receive the benefit of their bargains and should not be subject to losing those benefits under capacity releasing procedures.

D. No-Notice Transportation Service

New § 284.8(a)(4) adopted by Order No. 636 requires pipelines to provide a no-notice transportation service if they provided a bundled, city-gate, firm sales service on May 18, 1992. The preamble explained that this was required only if the sales service was provided on a no-notice basis.[193] Section 284.8(a)(4) describes no-notice service as "a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty."

1. Nature and Definition of no-noticeTransportation

Petitioners raise a variety of questions about the nature and definition of no-notice transportation.

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193. Order No. 636 at p. 30,421.

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The APGA raises the fundamental question about whether no-notice transportation obligates pipelines to deliver gas or simply to provide capacity. The APGA questions how a transportation service can be as adequate and reliable as a bundled sales service. Similarly, Citizens Gas & Coke Utility (Citizens Gas) argues that no-notice transportation service is not comparable to the currently available no-notice sales service because the Commission has not adopted provisions providing for the necessary gas supply. City Gas asks the Commission to clarify that no-notice transportation service will be available at the same quality level as the no-notice bundled sales service.

For other reasons, the pipeline industry also is concerned about the gas supply issue. INGAA and several pipelines[194] ask the Commission to clarify that the pipeline is not the guarantor of gas supply as was the case under the bundled, city-gate, firm sales service. For example, ANR argues that no-notice shippers must take responsibility that their supplies are adequate with the pipeline covering genuine market swings from nominations but not covering any shortages or imbalances, regardless of the cause or magnitude. PGT and Alabama-Tennessee argue that they cannot perform no-notice service or be the guarantor of adequate gas supplies because they have no storage. ANR states that to provide that back-up, the pipeline would have to "maintain an expensive inventory of redundant gas supply and/or capacity to ensure that deliveries are made to all shippers under all circumstances."[195] Tenneco maintains that the borrowing of gas will not solve any delivery problems at peak if the customers' gas has not been tendered to the pipeline.

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194. *E.g.*, Southern, Questar, CNG, Carnegie, Northwest, and ANR.

195. Petition at 8.

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The Commission clarifies that the pipeline is required only to provide the capacity and operational flexibility necessary to ensure no-notice delivery of gas supplies owned by the pipeline's customers. It is up to the pipeline's customers to provide the gas for this service. The pipeline is not required to provide a back-up sales service to cover shortages or imbalances other than normal balancing associated with system integrity and efficiency. However, as part of that balancing service, a pipeline offering a no-notice transportation service must establish procedures to accomodate short-term reasonable differences between customer nominations for takes from the pipeline and actual takes of gas from the pipeline.[196] It is up to the pipeline's customersto make sure that sufficient gas is tendered to the pipeline to correct such imbalances in a timely fashion. The pipeline is required only to provide physical resources and operational procedures needed to accommodate such imbalances. Because pipeline systems differ, the parties to the restructuring proceedings must define the meaning of short-term reasonable differences and the time in which imbalances must be corrected.

The Commission does not agree that a lack of storage excuses a pipeline from its no-notice obligations. If a pipeline has been able to provide bundled sales service with a no-notice characteristic, the Commission will require that the pipeline use the same physical and operational assets to provide a no-notice

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196. The procedures used to accommodate short-term differences between nominations and actual deliveries to the customer can involve several individual services that together provide the no-notice transportation service. For example, the pipeline may offer to provide no-notice transportation where it balances the customer's imbalance out of the customer's gas in contract storage or the pipeline's own storage gas, with the customer making up the use of the pipeline's storage gas in a reasonable period of time.

transportation service. Even where a pipeline has no storage, it can maintain operational control over gas receipts by issuing operational flow orders or by acting as the scheduling agent for its shippers (if they so choose), if necessary to provide no-notice transportation. Such operational control will, for example, enable the pipeline to build line pack in advance to support peak delivery requirements.

The Commission, however, is also encouraging pipeline shippers to cooperate with the pipeline in developing arrangements to efficiently implement no-notice service. For example, this could be accomplished by having contractual arrangements that allow the borrowing of gas by one customer from another customer.

NGSA argues that the definition of no-notice transportation is unclear. NGSA is concerned that the current definition could be viewed as requiring a single, restrictive no-notice service rather than permitting the flexibility needed to ensure optional services. NGSA asks the Commission to clarify that "no-notice transportation service simply entails an optional enhancement of basic firm transportation services which gives the firm transportation customers greater flexibility to meet unscheduled requirements within certain tolerances."[197] NGSA describes "tolerances" as degrees of flexibility above and below the customer's nomination within which it will not be penalized; that is, "an excused nomination inaccuracy." NGSA maintains that the degree of nomination inaccuracy permitted is a matter for negotiation between the pipeline-transporter and its shipper customers. United Distribution Companies asks the Commission to revise the rule to prohibit pipelines from restricting 'no-notice' service to limited or 'peak day' periods. The Industrial Groups argue that clarification is needed about whether the customer

197. Petition at 18.

may demand 100% of its post Order No. 636 firm transportation service, rather than some lesser percentage, to be provided under a no-notice FT rate schedule. ANR argues that pipelines should be entitled to impose daily penalties on a nondiscriminatory basis because flow control installations would be very expensive.

As a general matter, the Commission observes that some of the arguments made concerning alleged problems with no-notice transportation service appear to be thinly veiled arguments by those who favor continued pipeline bundled sales service. The Commission makes it clear that: 1) no-notice transportation service must be offered, as required below, as a pipeline service; 2) no legitimate operational reason has been given why no-notice transportation service cannot be as reliable as no-notice bundled sales service; and 3) the Commission will not tolerate *any* attempt to frustrate the orderly operation of no-notice transportation service. Thus, the pipelines are required to offer 100 percent no-notice service on all days of the year. However, the pipelines are encouraged to offer additional variations of no-notice service, if that suits the needs of their customers as suggested in Order No. 636.[198]

As stated above, several petitioners (e.g., the APGA) refer to the no-notice transportation service as hypothetical or untested or untried. However, the Commission, as stated above, believes it is fully warranted in its prediction that the pipelines can provide a reliable no-notice transportation service.[199] In Order No. 636, the Commission briefly described in general how the

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198. "The pipeline could also offer different daily imbalance management options based on a customer's desired tolerance above expected scheduled quantities and allowed tolerances." Order No. 636 at p. 30,425.

199. *See* Mississippi River Transmission Corp. v. FERC, *supra*, ("No

(Cont'd)

pipelines could provide that service to their former sales customers.[200] In the next sections, the Commission will further explain how it envisions no-notice transportation service could be provided.

a. Example: Production area-to-market pipeline with storage

Under a no-notice transportation service, a shipper could nominate and schedule its anticipated daily requirement from suppliers attached to the pipeline. During the gas day the shipper could be permitted the flexibility to take delivery of gas greater or less than its scheduled volume, within its maximum daily quantity (MDQ), resulting in a daily imbalance on the pipeline. The pipeline could handle the imbalance by adjusting injections or withdrawals from storage, or to a lesser extent, by increasing or decreasing line pack.

Pipelines could utilize unused contract storage capacity and deliverability to cover a shipper's daily imbalances. Gas withdrawn from storage could be borrowed from or displaced with customer storage accounts and replaced within days when the no-notice shipper corrected its imbalance. To assure that contract storage is available when called upon by the contract storage customer, the pipeline could limit no-notice overtakes when storage customer withdrawal nominations approached maximum storage deliverability or when working gas was below certain levels. If contract storage usage patterns routinely leave

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legitimate explanation being apparent, we see no reason to question FERC's implicit conclusion that bundled and unbundled service are adequate substitutes for each other." slip op. at 10).

200. Order No. 636 at p. 30,425.

contract storage capacity or deliverability unavailable for imbalance management, the pipeline could use retained storage to support the no-notice service. If operating conditions require limitations of no-notice service, these limitations should not be any more restrictive than those that existed for bundled sales service as of May 18, 1992.

b. Example: Downstream pipeline

This example applies to no-notice transportation service on a downstream pipeline that currently purchases gas from one or more upstream pipelines. Under the final rule, capacity on upstream pipelines must be assigned to the downstream pipeline's customers wanting that capacity, but, the downstream pipeline can also retain some upstream capacity to support the no-notice service, but only when it has demonstrated the need to hold this capacity to fulfill its no-notice service obligation. If the downstream pipeline does not retain upstream capacity for this purpose, one possible way in which it could provide the no-notice service is for the customers of the downstream pipeline to grant it agency rights to schedule no-notice services on upstream pipelines.

A no-notice shipper on a downstream pipeline could nominate its daily requirement, specifying volumes to be received from individual upstream pipelines. However, the downstream pipeline could perform the actual nomination and scheduling of the shipper's no-notice service on the upstream pipeline. Thus, when a customer on the downstream system invoked its no-notice right to take more gas, for example, than scheduled on that day, the downstream pipeline could in turn take more no-notice gas from the upstream pipeline than scheduled. When multiple upstream pipelines are involved, the downstream pipeline could follow a prespecified order in

selecting the upstream no-notice service, as specified by the downstream shipper. The downstream pipeline could override the preferred priority order, to use different receipt points for example, as necessary to maintain system integrity. Thus, the no-notice imbalance could be handled by adjusting takes from the upstream pipeline as needed to keep the downstream system in balance. Reliance on upstream no-notice services, with operating control in the hands of the downstream pipeline, provides downstream systems the ability to provide no-notice services even if they possess no storage of their own.[201]

2. Availability of No-Notice Service

INGAA, United Gas Pipe Line Company (United), ANR, and CIG ask the Commission to limit no-notice transportation service to existing sales customers at current delivery points with the option to provide the service beyond that on a nondiscriminatory basis if the pipeline has the facilities and delivery capacity.

Northwest asks the Commission to clarify whether pipelines must offer a no-notice transportation service option to customers that have already left the pipelines' traditional sales service for pre-Order No. 636 transportation. Northwest states that no-notice service without balancing and scheduling penalties does not now exist on its system and seeks clarification that it does not have to rebundle to a quality level which exceeds traditional bundled sales.

Questar argues that a shipper should be entitled to no-notice transportation service only if it asks for it during the restructuring proceeding.

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201. The imputed load factor for the small customers' firm transportation rate applies to "no-notice" transportation as well.

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NASUCA asks the Commission to clarify that "all pipelines should be required to offer a no-notice transportation service in the future regardless of whether they were providing a bundled, city-gate, firm sales service on the effective date of the rule."[202] Similarly, Southwest Gas Corporation (Southwest Gas) states that the Commission must ensure that pipelines already unbundled, such as El Paso Natural Gas Company (El Paso), must be required to perform a no-notice transportation service to avoid any undue discrimination.

The pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no-notice firm, city-gate, sales service on May 18, 1992. The pipeline must provide no-notice service at flexible delivery points for those customers. Pipelines that did not provide a no-notice sales service on May 18, 1992, are not required, but are strongly encouraged, to offer a no-notice transportation service. The pipeline's sales customers must inform the pipeline in the restructuring proceedings what form of transportation service they want to receive starting on the effective date of the pipeline's compliance filing. This is a one-time right to elect no-notice transportation. The pipelines are not required to offer no-notice service to other customers because they have not been receiving such a service.

A pipeline may, of course, offer no-notice service to transportation customers other than those who qualify for such service. If a pipeline offers to provide this service to a broader group of customers than required, the pipeline is required to do so on a non-discriminatory basis and, to the extent capacity is available, customers may then elect no-notice service at any time. The Commission strongly encourages the pipelines to make

202. Petition at 33.

no-notice transportation service available to the maximum extent possible.

3. Direct Sales

The Industrial Gas Users Conference asks the Commission to indicate how, if at all, Order No. 636 affects nonjurisdictional direct sales arrangements. It states that the Commission probably intended to unbundle direct sales service. If so, it argues that those customers should have access to the full range of transportation rights and services, including no-notice firm service, traditional open access firm transportation, and storage.

Direct sales must be unbundled under Order No. 636.[203] Direct sales customers are entitled to receive the same type of transportation service that was embedded within their bundled direct sales service.[204] Hence, they are entitled to receive no-notice transportation service only if their direct sales were provided on a no-notice basis. Similarly, they are entitled to an allocation of firm storage only if firm transportation was embedded within their direct sales service.

4. The Meaning of Firm Entitlement

Section 284.8(a)(4) of the regulations promulgated by Order No. 636 provides that:

> An interstate pipeline that provided a firm sales service on May 18, 1992, and that offers

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203. 18 CFR 284.284(b) and (c) convert bundled sales under any service agreement to unbundled service.

204. See *infra* on storage.

> transportation service on a firm basis under subpart B or G of this part, must offer firm transportation service under which firm shippers may receive delivery up to their *firm entitlements* on a daily basis without penalty.[205]

The Industrial Groups question what "firm entitlements" refers to and ask whether they are 'firm entitlements' under (1) its existing firm sales contracts, (2) its existing firm sales and transportation contracts combined, or (3) the new firm transportation entitlements in the service agreements to be entered into under the new no-notice FT rate schedules.

The Commission clarifies that "firm entitlements" refers to the firm shippers' daily right to receive transportation service. As stated *supra*, the firm shipper has a right to receive a no-notice transportation service only if it received a no-notice sales service on May 18, 1992. Under section 284.284(b) of the regulations adopted by Order No. 636, the sales customer's firm rights are converted to an equivalent amount of firm transportation service. Hence, firm entitlements means the converted firm entitlements to which a shipper is entitled to receive no-notice transportation service under Order No. 636.

5. The Meaning of Equivalent Amount of Transportation Service

Under new section 284.284(b), a pipeline customer's firm sales entitlements are converted to an equivalent amount of unbundled firm sales service and an equivalent amount of unbundled firm transportation service, except as adjusted in the

205. 18 CFR 284.8(a)(4) (Emphasis added.)

restructuring proceedings. Texas Gas sees an ambiguity between section 284.284(b) and the preamble to Order No. 636, which states that pipelines may offer a bundled transportation service consisting of transportation and storage to perform no-notice service. Texas Gas asks for clarification that former bundled sales customers are to receive the same quality and quantity of transportation service they were previously receiving before unbundling.

The Commission clarifies that former bundled sales customers are entitled to receive the same quality and quantity of transportation service they were previously receiving as part of their sales service before unbundling. The Commission's reference to a bundled transportation and storage service was meant to highlight one of several possible ways to achieve that result through use of no-notice transportation service. The Commission notes that the central point is that the no-notice transportation must be at least as reliable as the service the bundled sales customers were actually receiving. On many systems, the pipelines could not deliver their full daily contract demand obligation on every day of the year because that was operationally impossible. The Commission is not requiring the no-notice transportation service to be superior to the bundled sales service in that respect.

6. Timing of Implementation

The Wisconsin Distributor Group states that it is concerned about the difficulties in implementing no-notice service and suggests a transition period where a pipeline would offer both bundled sales and no-notice transportation with an annual conversion process.

Elizabethtown Gas Company (Elizabethtown) argues that

the Commission erred by not ordering the implementation on an interim basis, as it did in the case of Transcontinental Gas Pipe Line Corporation (Transco), with a conference on each pipeline after one year's operation.

The requests have not indicated a need for generic interim or transition periods with respect to implementation.

7. Flow Control

CIG asks the Commission to clarify that "imposition of operational conditions requiring that no-notice shippers maintain storage inventory levels and flowing gas supplies in the same relative mix as the pipeline currently relies upon to operate its sales service is consistent with the concept of no-notice delivery service."[206]

ANR asks the Commission to clarify that pipelines "cannot be held liable to producers, shippers, or consumers, as a result of any actions taken pursuant to [operational flow] orders."[207] ANR seeks clarification that for operational reasons it can order shippers located in an area to buy gas, whether their specific market area requires it or not. Last, ANR argues that pipelines should be able to impose daily penalties on a nondiscriminatory basis because flow control installations are very expensive.

Cincinnati Gas argues that allowing parties to craft operational control provisions in the restructuring proceedings is fundamentally inconsistent with pipelines retaining operational control to the degree they have it today.

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206. Petition at 15.

207. Petition at 9.

Appendix C

United Distribution Companies asks the Commission to revise the rules to prohibit pipelines from unilaterally imposing "flow control" or other control devices restricting LDC ability to take gas at city-gate stations.

The Commission clarifies that pipelines have the right to impose reasonable operational conditions and to issue, on a nondiscriminatory basis, operational flow orders without liability, except for negligence or undue discrimination, to be able to provide a no-notice transportation service. The Commission sees no inconsistency between permitting parties to participate in crafting the operational control provisions needed for no-notice service and the pipelines retaining operational control. Of course, the pipeline must include in its tariff all operational terms and conditions related to no-notice transportation service so that the Commission can review the reasonableness of those terms and conditions, and so that shippers will have notice as to what will be asked of them.

The Commission views the control of flow from the pipeline to the city-gate as an important issue to be resolved in the restructuring proceedings. The parties should consider flow control devices as well as other methods, such as the use of overrun penalties. The Commission will not permit penalties for service within daily firm entitlements covered by no-notice service. If a pipeline elects to impose flow control or other control devices, the Commission will consider any opposition to that election in the compliance filing order.

8. Control of Facilities

United asks the Commission to "confirm that each pipeline's own characteristics must be taken into account in the settlement proceedings which will restructure individual proceedings" and

to make an explicit statement of the pipeline's need to have adequate control over its operations "because of the bidirectional flow necessary to maintain peak capacity." The Commission so confirms, as long as it is accomplished on a non-discriminatory basis.

9. Supply Reallocation/Borrowing

In Order No. 636, the Commission suggested the possibility that parties could agree to the borrowing of one customer's gas to ensure no-notice transportation service for another shipper.

NGSA requests clarification with respect to the "borrowing" of a shipper's gas to keep the system in balance and to provide no-notice service. It urges that the LDC may only take gas belonging to the LDC and that once an interruptible shipper's gas is in the system it may not be diverted unless pursuant to a contractual arrangement between the LDC and the interruptible shipper. Phillips similarly argues that pipelines should be able to take producers' supplies for operational and no-notice purposes only pursuant to contract and suitable compensation.

United asks the Commission to explicitly recognize that the pipelines will have no liability for supply curtailment or reallocation among customers conducted under the terms of their individual tariffs.

The State of Louisiana seeks clarification that "a pipeline may [not] 'borrow' gas from some customers to serve others at a time when the customer from which the gas is 'borrowed' itself has need for the gas."[208]

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208. Petition at 6.

The Commission views the pipeline's rights and obligations in connection with the borrowing of gas as matters to be addressed and resolved in the individual restructuring proceedings. As the above example of no-notice transportation in this Part illustrates, it is necessary to balance the pipeline's need to borrow gas with its obligation to return borrowed gas on demand. These matters are pipeline-specific depending on particular pipeline needs and must be included in the pipeline's tariffs so that the Commission can determine if they are reasonable and so shippers will have notice of what might happen. As a general matter, the Commission believes that a borrowing of gas should be pursuant to contract and appropriate compensation.

10. Effects of No-Notice Transportation on Other Services

SoCal Edison asks the Commission to clarify Order No. 636 by adopting a "quality of service" principle to ensure that existing transportation customers are treated in a non-discriminatory fashion when pipelines implement their tariff provisions and operating conditions for no-notice transportation. It argues that this is especially important to ensure that existing transportation customer gas is not curtailed before, or in a discriminatory manner with respect to, no-notice gas.

The Fuel Managers Association seeks clarification that no-notice transportation "may not degrade the 'traditional' firm transportation service."[209] It asks that the Commission clarify that a pipeline may not divert traditional firm transportation gas supplies or interrupt that service to meet the needs of no-notice customers. Similarly, the Industrial Groups are concerned that

209. Petition at 9. See also Destec.

pipelines may undermine traditional firm service by 'prioritizing firm customers' call on line pack to provide 'no-notice' service.

Brooklyn Union, *et al.*,[210] PSE&G, and AGD ask the Commission to clarify that the operating restrictions of no-notice transportation will not impair other existing firm services or create more onerous conditions on existing firm transportation and contract storage services.

As a general matter, the Commission agrees that existing transportation and storage services should not be diminished in quality. However, as with the borrowing of gas discussed above, the parties to the restructuring proceedings should resolve questions concerning the relationship of no-notice transportation to other pipeline services in each proceeding. Of course, the pipeline must include all of its operational terms and conditions in its tariff so that the Commission can determine if they are reasonable and so that all shippers will know the terms and conditions of the no-notice service.[211]

11. Unbundling Options

The APGA asks the Commission to clarify that a sales customer, upon unbundling, can elect either no-notice or traditional transportation service. The Commission clarifies that upon unbundling a sales customer, at its election during the

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210. ConEd and PSE&G.

211. The Commission, as requested by Brooklyn Union, *et al.*, confirms that holders of firm storage capacity have priority to use of that capacity, subject however, to the pipeline's tariff provisions with respect to storage use and the availability of interruptible storage when operationally warranted. Order No. 636 at p. 30,427.

restructuring proceeding, may choose no-notice or traditional firm transportation or a combination of the two. However, as stated above, the customer may elect no-notice transportation only at that time unless the pipeline offers no-notice transportation in the future as a service to all customers.

12. Other Forms of Transportation Service

Tejas, in its supplemental motion for clarification, asks the Commission to clarify that pipelines may offer transportation service in addition to no-notice and traditional firm transportation. Tejas refers to Columbia's "off-peak" firm service.[212] And Tejas suggests that a short-notice service priced between no-notice and traditional service might prove adequate for many customers.

Destec suggests that the Commission require an off-peak firm transportation service that is subject to interruption to provide no-notice transportation.

The Commission clarifies that the pipelines may offer transportation services in addition to no-notice and traditional firm transportation services.

13. Costs

The Industrial Groups argue that, on rehearing, the Commission should specify that all costs, direct or indirect, of providing no-notice service must be recovered in the rates for that service. The matter of the appropriate costs to be allocated to no-notice transportation will be addressed by the Commission

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212. Columbia Gas Transmission Corp., 54 FERC ¶ 61,226.

in the restructuring proceedings. As required by section 284.14(g) of the regulations, the pipeline must file tariff provisions implementing no-notice transportation service, with separately identified cost components.

14. Instantaneous Service

Gas Company of New Mexico asks the Commission to require pipelines to provide instantaneous delivery service that "would permit a shipper 'instantaneously' to schedule and deliver additional gas without waiting the 1-2 day period generally required by pipeline scheduling procedures."[213] The Commission denies Gas Company of New Mexico's request. While the Commission is requiring pipelines to provide instantaneous transportation service (see 18 CFR 284.14(b)(vii)), it is not mandating any change to pipeline scheduling and delivery requirements for traditional open access transportation service. Gas Company of New Mexico also asks the Commission to require pipelines to provide "instantaneous service" whenever (1) immediate action is required to avoid overpull or similar penalties, and (2) it would not be possible to schedule additional gas in time to avoid the problem. It adds that instantaneous service is a necessary adjunct to no-notice service and like no-notice service should be mandatory. Pipelines must provide instantaneous transportation service (see 18 CFR 284.14(b)(vii)) but, in the case of traditional open access transportation service this is only after the shipper's gas has been scheduled and delivered to the pipeline for transportation pursuant to its tariff requirements. The relationship between instantaneous service and no-notice service must be addressed in the restructuring proceedings.

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213. Petition at 14.

Appendix C

E. Storage

Order No. 636 amended § 284.1(a) of the Commission's regulations to define transportation as including storage. This means that pipelines must offer their customers firm and interruptible storage on an open-access, contract basis. Order No. 636 stated that pipelines can retain storage capacity downstream of the place of unbundling solely to fulfill their obligations with respect to system management (load balancing) and no-notice transportation. In addition, a pipeline can retain some storage capacity upstream of the place of unbundling in order to perform its sales service as follows:

> The allocation of this capacity between the pipeline, for use to make sales, and others, of course, must be done on a nondiscriminatory basis and the costs associated with the upstream storage capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream storage capacity (*e.g.*, injection and withdrawal requirements).[214]

1. Allocation of Downstream Storage Capacity

Order No. 636 stated that the method for allocating downstream storage capacity should be addressed in the restructuring proceeding. Order No. 636 only required storage capacity to "be allocated on an even, nondiscriminatory basis

214. Order No. 636 at p. 30,427.

among all shippers without regard to the seller of the gas."[215] Order No. 636 also stated that "[a]ny allocation of storage capacity, however, must take into account pipeline capacity needs for load balancing and system management and the need to reserve some level of storage capacity for the pipeline or *for shippers in connection with the pipeline's no-notice transportation service.*[216]

Numerous petitioners argue that current bundled sales customers should have priority in the allocation of storage to maintain their level of maximum daily entitlement to service.[217] Memphis Light refers to the queue exemption for conversions from firm sales to firm transportation under Section 284.10(c) of the Commission's regulations.[218] The APGA maintains that sales customers with "eligible firm sales service agreements" have automatic rights to storage now that it is defined as transportation. The APGA adds that Section 284.10(c) should be revised and expanded to include those sales customers without "eligible firm sales service agreements." Colorado Springs argues that the right to storage for current sales customers should be on an individual storage facility basis. Southern Indiana

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215. *Id.*

216. *Id.* (emphasis added).

217. Illinois Commerce Commission, Memphis Light, Gas and Water (Memphis Light), Rochester Gas, Citizens Gas, City of Colorado Springs, Colorado (Colorado Springs), Illinois Power, Columbia Gas Distribution Companies, APGA, Citizen Action, Indiana Gas, Alabama Gas, UGI , City Gas, United Distribution Companies , Brooklyn Union, and Questar.

218. See Order No. 436 at p. 31,516-517. Section 284.10(c) provide firm sales customers with "eligible firm sales service agreements" with the right to convert to firm transportation service under Part 284.

asserts that the splitting of storage will render it meaningless.[219] ANR contends that the preemptive right to storage should not be tied to no-notice service and that "on an integrated storage network such as ANR's, individual customers should not be permitted to choose which particular storage field the pipeline will utilize to render storage service to them" in order to "avoid a lowering of the overall storage capacity available to the market."[220]

The Commission clarifies that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service. This is whether or not they elect no-notice transportation service. This right will enable pre-Order No. 636 customers buying gas under a small customer rate schedule to obtain storage needed to maintain their level of maximum daily entitlement in combination with the transportation service they elect whether it is no-notice or regular firm transportation. APGA's arguments about Section 284.10(c) are, therefore, moot. The actual allocation of storage facilities is a matter for the restructuring proceedings.

The Northern Distributor Group, Northern Illinois Gas, and Illinois Power argue that customers that have already converted should be entitled to storage on the same footing as customers converting under Order No. 636, without paying a premium. Northern Illinois Gas adds that system users should have priority over gas sellers for additional capacity. The Commission concludes that previously converted customers should not be entitled to storage on the same footing with customers converting under Order No. 636. This is because the customers that

219. Columbia Gas Transmission Corp., 53 FERC ¶ 61,366 (199).

220. Petition at 19, 20.

converted earlier were able to do so without storage to meet their needs. If storage is available after converting customers elect their storage levels, the pipeline must offer and allocate the remaining storage among all its shippers on a non-discriminatory basis. That is, current system users will have no priority over new transportation customers for additional storage capacity that is not selected by converting customers.

2. Upstream Storage

Order No. 636 provides that pipelines may retain storage capacity upstream of the place of unbundling to support their unbundled sales service.[221]

NGSA argues on rehearing that there is no justifiable basis for allowing pipelines to reserve upstream storage capacity to support their sales services. NGSA includes within its argument all capacity upstream of the unbundling point. They argue that "[u]pstream storage is equally capable of giving pipeline sales service an unfair competitive advantage" for the same reasons that apply to downstream storage (such as seasonal price arbitrage, transmission capacity supplementation, flow regulations and balancing). They are concerned that a "pipeline can offer any transportation service upstream of this point *unequally* to advantage its sales service."[222] NGSA also states that "[i]f the Commission clarified on rehearing that all shippers had an equal opportunity to purchase rights on the upstream facilities, the unbundling point distinction would become benign."[223]

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221. Order No. 636 at p. 30,427.

222. Petition at 10.

223. *Id.*

On the other hand, Transco and Brooklyn Union argue that pipelines should able to retain some production area storage downstream of the place of unbundling to avoid gerrymandering the place of unbundling to retain storage for its merchant service, even though unbundling could occur at the wellhead. Both view this issue as appropriate for the restructuring proceedings.

The Commission adheres to the conclusion in Order No. 636that pipelines may retain a share of production area storage upstream of the point of unbundling to support sales at the unbundling point. As stated in Order No. 636, and *supra* with respect to upstream production area capacity, the pipeline must allocate capacity between it, for use to make unbundled sales, and others on a non-discriminatory basis, and the costs associated with upstream capacity must be recovered by the pipeline solely as part of its market-based rates. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream capacity (*e.g.*, storage injection and withdrawal levels).

The Commission disagrees with Transco and Brooklyn Union because title must pass at the unbundling point and, therefore, the pipelines do not have gas to put into storage downstream of that point.

3. Existing Contract Storage Service

In Order No. 636, the Commission stated that "(a)ll current holders of storage capacity will retain that capacity under current contractual provisions."[224]

CNG states that it does not intend to reduce its customers'

224. Order No. 636 at p. 30,427.

contract storage capacity under current contractual provisions. However, CNG states that it must have the ability to adjust existing storage operational protocols (*e.g.*, storage injection and withdrawal schedules) to reflect the current status of its system operations as more customers became contract storage customers. It adds that without that ability, it might have to reduce aggregate available storage capacity.[225]

The Commission's intent was that current contract storage customers retain their full right to capacity as specified in their contracts. The Commission did not mean to infer that the terms and conditions associated with their rights could not be changed if they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage. This, of course, is a pipeline specific matter and must be addressed in the restructuring proceeding.

4. Transportation Associated with Storage

ANR asks the Commission to clarify that certain associated transportation is, in effect, operated as an integral part of ANR's storage complex, and therefore should not be "unbundled" to avoid stranding of valuable storage capacity. ANR states that it currently provides open access storage on that basis. ANR maintains that the same principle governs storage released or assigned, that is, the released or assigned storage should be tied to any associated transmission capacity.[226] The Commission

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225. The various answers and responses filed in connection with CNG's clarification request are acceptedinto the record.

226. ANR further seeks clarification about whether the storage volumes contained in the storage fields at the time of the release or assignment are

(Cont'd)

believes that this matter should be addressed in ANR's restructuring proceeding.

5. Storage Fields Disconnected From System

ANR states that it "owns certain storage fields that are physically disconnected from its system, but gas is moved to and from those storage facilities by means of transportation and exchange agreements with third party pipelines."[227] It argues that it should be to able treat these arrangements as an "integrated storage network"[228] to avoid "disynchronized allocations of storage, transmission and related transportation and exchange agreements [which] would render the operational continuity of the pipeline network into a meaningless state. . . ."[229] The Commission clarifies that storage disconnected from a system should be treated in the same manner as storage connected to the system and be allocated as determined in ANR's restructuring proceeding. However, the mere fact of disconnected storage cannot be used as a basis for discrimination with respect to related exchange or transportation agreements.

(Cont'd)
required to be released or assigned along with the storage. The Commission also believes that this matter should be addressed in the restructuring proceedings.

227. Petition at 18.

228. *Id.*

229. *Id.*

6. Leased Storage

ANR requests clarification that "storage capacity provided by leased facilities, and storage capacity provided by storage service agreements, should be treated in a similar fashion with directly owned storage facilities, as part of an integrated market area storage system."[230] The Commission clarifies that leased storage should be treated as if it were pipeline-owned storage.

7. Storage Combined with Other Services

In Order No. 636, the Commission stated that a pipeline is "required to offer the open-access storage on a basis that is unbundled and not in any way tied or linked to the storage customer's purchases of any particular type of sales service."[231] Brooklyn Union argues that the Commission should clarify that the rendition of storage service cannot be tied or linked to a customer's purchase of transportation or any other service offered by the pipeline. It maintains that some storage fields, *e.g.*, Leidy Storage Field, are connected to several pipelines. The Commission agrees that as a general matter pipelines may not tie services. Whether transportation and exchange arrangements can be packaged with the storage service is an issue to be resolved in each proceeding and will depend upon the configuration of the facilities and other operational factors. If, for example, there is no other way to get the gas into or out of a particular storage facility than through a particular transmission lateral, then it may be reasonable to combine the services.[232]

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230. Petition at 19.

231. Order No. 636 at p. 30,426.

232. Tennessee Gas Pipeline Co., 59 FERC ¶ 61,045 (1992).

Appendix C

8. Storage Reporting

In Order No. 636, the Commission instituted semi-annual reporting requirements with respect to the new open-access storage. The Independent Petroleum Association of America and Cooperating Associations (IPAA) states that more frequent reports are required and requests that each pipeline update the Section 284.106(g) data on a weekly basis and post such report on its electronic bulletin board.

Llano, Inc. (Llano) a pipeline providing Section 311 transportation, argues that semi-annual reporting is not needed in light of the monthly storage data collected by the EIA. It further contends that the required data is commercially sensitive and that the reporting requirements on small intrastate systems is not cost justified.

The Commission concludes that it is appropriate to require semi-annual reporting for all pipelines providing storage. This coincides with the injection and withdrawal cycles for storage activities. Further, the Commission in sections 284.8(b)(3) and (4) and 284.9(b)(3) and (4) of the regulations is requiring pipelines to post the availability of capacity in storage fields on the EBB. The precise nature of the information is to be developed in the restructuring proceedings. As the Commission gains experience, it may revisit this issue to determine whether more or less reporting is needed.

The Commission notes that the EIA does not collect data by individual customer nor does it collect rate and revenue data. Further, the information to be reported to the Commission on an semi-annual basis is similar to that currently reported by intrastate pipelines on an individual transaction basis for

transportation services subject to Part 284, Subpart C. In addition, the Commission will consider individual requests for waiver from the reporting requirements.

Llano argues that the Commission erred by not providing notice of the new semi-annual storage reporting requirements for intrastate pipelines. The Commission disagrees. First, the Commission requires reporting for transportation and storage that is now transportation so storage reporting is merely an aspect of transportation reporting. Second, even if considered a new reporting requirement, it is intimately connected with the authorization for intrastate pipelines to provide open access, contract storage to which Llano does not object.

F. Market Centers

In Order No. 636, the Commission adopted new regulations, Sections 284.8(b)(5) and 284.9(b)(5), which prohibit any provision in a pipeline tariff that would inhibit the development of market centers. The Commission believes that inter-pipeline market centers will enhance the efficient operation of the natural gas market and aid competition by creating markets where gas sellers from different production areas can meet gas purchasers from different market areas using different pipelines. Section 284.1(c) defined market centers as "an area where gas purchases and sales occur at the intersection of different pipelines."

Peoples Gas argues that the Commission should expand its definition of market center to include market-area in-line transfer points or areas on individual pipeline systems where title can passbetween buyers and sellers.

Natural Gas Clearinghouse asks the Commission to amend

the market center definition to recognize that "market centers" already exist at both interconnect and non-interconnect points on individual pipeline systems, *e.g.*, at pooling points and plant outlets, as can be seen by a quick review of the "Index" prices published by various trade press publications."[233] Natural Gas Clearinghouse suggests the following definition of market center.

> §284.1(c) Market center means an area where gas purchases and sales occur, for example, at the intersection of different pipelines or at recognized aggregation areas or pooling points on a specific pipeline.[234]

The Commission will not expand its definition of market center because it is not necessary to achieve the Commission's goal of not inhibiting the development of areas where purchases and sales of gas can occur. For example, the Commission, as stated in Order No. 636, will not permit actions that inhibit the development of pooling areas. While pooling areas and market centers are different concepts, title transfers may occur at pooling areas around the production areas.[235] However, the Commission will not resolve the in-line transfer issue until it has a specific proposal before it.

G. Pooling Areas

In Order No. 636, the Commission stated that it will not mandate production area pooling areas on individual pipelines

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233. Petition at 14.

234. *Id.*

235. Order No. 636 at p. 30,428.

for the aggregation of supplies by all merchants. The Commission did state, however, that it will not permit actions that inhibit the development of pooling areas.

Natural Gas Clearinghouse states it is willing to address the pooling area issue in the individual restructuring proceedings "*[p]rovided*, however, in order to provide substance to the Commission's requirement that pipelines allow for flexible receipt and delivery points, the Commission should clarify that each pipeline must provide shippers with a workable means to aggregate supplies and markets and should affirmatively state the implementation of pooling or paper pooling is one way to satisfy this requirement."[236]

As the Commission stated in Order No. 636, it is not mandating pooling areas. However, the Commission will not permit any actions that inhibit their development. Pipelines should work with shippers to develop a workable means to aggregate supplies. This is a matter to be considered in the restructuring proceedings. For example, in Order No. 636, the Commission stated that pipelines should consider entering into "operational balancing agreements" with other gas merchants to permit them to balance, in the aggregate, for all of their gas purchasers shipping on the pipeline.

H. Flexible Receipt and Delivery Points

Order No. 636 modified the Commission's policies with respect to flexible receipt and delivery points to provide for more flexibility. Order No. 636 first provided that pipelines must give firm shippers flexible delivery points in the distribution areas.

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236. Petition at 13 (emphasis in original).

This means that firm shippers will have the right to change firm delivery points and to use other delivery points on a interruptible basis without losing their priority for firm service.

Order No. 636 also expanded shippers' rights with respect to flexible receipt and delivery points outside the production area receipt points and inside the distribution area delivery points by including the right to receive gas from any person at any place on the system and the right to deliver gas to any person at any place on the system on a firm basis, with the flexibility to change firm receipt and delivery points and to use all delivery points on an interruptible basis.[237]

In addition, Order No. 636 stated:

> Of course, receipt and delivery points must be within the firm transportation capacity to which the shipper is entitled, and for which it pays. So, for example, an LDC in a downstream region of the country could arrange to deliver gas to an LDC or an industrial in an upstream region, but conversely an LDC in an upstream region could not arrange for delivery in a downstream region.[238]

That is, flexibility is allowed only "within the path" of the shipper's service.

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237. Order No. 636 at p. 30,429.

238. *Id.*

Appendix C

1. Opposition to Flexible Receipt and Delivery Points

Atlanta Gas argues that the Commission "should eliminate its policy mandating flexible receipt and delivery points . . . [and] [t]o the extent flexibility is appropriate, it should be the subject of negotiation among affected parties, with appropriate conditions placed on the exercise of flexible receipt and delivery point rights."[239] Atlanta Gas maintains that the Commission's policy will result in destructive, often one-sided, competition by downstream LDCs and may subject LDCs utilizing flexible delivery points in other states to NGA regulation by transporting in interstate commerce rather than local distribution.

The Commission believes that flexible receipt and delivery points will promote maximum efficient usage of the pipeline system, are necessary to the development of market centers and to the achieving of a meaningful capacity releasing program. Thus, flexible receipt and delivery points should promote competition in the natural gas industry to the benefit of gas consumers.

The Commission does not believe that an LDC, by shipping gas to a delivery point outside its home state subjects itself to NGA jurisdiction. The LDC is not a transporter of gas in interstate commerce because it is not operating the system or controlling access by others any more than under existing transportation arrangements without flexible delivery points.[240]

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239. Request for Rehearing at 14.

240. *Cf.* Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992) and El Paso Natural Gas Co., 59 FERC ¶ 61,031 (1992).

2. Current Rights to Receipt and Delivery Points

Equitrans, Inc. (Equitrans) asks the Commission to clarify that prior Part 284 firm conversions are not terminated or existing firm receipt point capacity reallocated in order to make accommodations for later-in-time conversions under Order No. 636.

CIG similarly asks for clarification that flexible receipt and delivery points do not require existing capacity holders at the changed receipt and delivery points to be "bumped" in order to accommodate a change.

INGAA requests the Commission to clarify that flexible delivery points are subject to availability. It states that "if, for example, the system is fully booked, the pipeline should be allowed to grandfather existing delivery points, or provide flexibility on an as needed basis."[241]

Northern Illinois Gas asks the Commission to promulgate specific guidelines with respect to the use of flexible delivery points within a distribution area. For example, it maintains that the use of a flexible delivery point should never be able to preempt or require curtailment of a preexisting firm delivery point.

The Commission clarifies that current shippers that retain their firm capacity rights during the restructuring proceedings also retain their priorities at designated receipt and delivery points and may not be bumped, preempted, or curtailed under the flexible receipt and delivery point policy.

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241. Petition at 11.

Appendix C

3. Nature of Flexible Receipt and Delivery Points

Hadson states it is concerned about the priority principles governing flexible receipt and delivery points. It perceives a contradiction in the Commission's statement that firm shipments may displace interruptible shippers on reasonable notice and the statement that alternate firm points may be used on an interruptible basis.

Peoples Gas argues that the Commission "should specify that service in the distribution area to a 'flexible' or alternate delivery point designated by a firm customer is inferior to service rendered to another firm customer that uses the same delivery point as a primary delivery point, but superior to other interruptible services at that delivery point."[242]

Southwest Gas contends that the Commission "must clarify that the ability to designate delivery points on a firm basis under a flexible delivery point policy must be limited by the availability of [firm] capacity at the designated delivery points."[243]

The Gas Company of New Mexico contends that firm service to a primary delivery point should always have a priority over firm service to a flexible delivery point.

The Commission clarifies that firm shippers' use of designated alternate/flexible delivery points is subject to the rights of firm shippers using those points as primary delivery points but is superior to the rights of interruptible shippers to

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242. Petition at 13.

243. Petition at 2, 3.

those points.[244] Hence, Order No. 636 was correct in describing the use of alternate/flexible delivery points as interruptible inasmuch as those rights are, as stated, inferior to primary firm delivery points.

4. Reasonable Notice — Priority

Cincinnati Gas asks the Commission to reinforce the absolute priority of firm transportation over interruptible transportation. It adds that the Commission "should make it clear that the 'reasonable notice' required for purposes of bumping interruptible transportation is to be defined in a manner that maximizes the priority of firm capacity."[245]

The Commission agrees that firm transportation has priority over interruptible transportation but cannot establish a generic standard for reasonable notice of bumping interruptible transportation.

ANR asks the Commission "to clarify that delivery point flexibility should not be mandated on a daily basis, and that the parties are free to develop the rules governing delivery point flexibility in their individual restructuring dockets."[246] It states

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244. Peoples Gas asks the Commission to "make clear that use by existing firm customers of existing capacity at distribution area delivery points, including the ability to shift firm entitlements from one division or plant to another, will not be adversely affected." Petition at 12. The Commission clarifies, but only to the extent that the existing firm customers bump interruptible and not firm shippers with primary rights.

245. Petition at 49.

246. Petition at 10.

that this is necessary to prevent the dramatic multiplication of operational difficulties that would be caused by the ability to switch no-notice delivery points on a daily basis.

The Fuel Managers Association argues that pipelines should be required to provide flexibility in scheduling receipt and delivery points up to the maximum technical ability if high technology equipment is available, or, if it is not, to make best efforts to provide the maximum flexibility in shipper scheduling.

The Commission endorses the idea that each pipeline should provide for maximum flexibility with respect to receipt and delivery point scheduling in light of the reasonable operational requirements of the pipeline. The Commission directs the parties to fashion procedures governing receipt and delivery point flexibility in the individual restructuring proceedings. If a pipeline, such as ANR, wishes to limit flexibility, it must demonstrate in that proceeding that the limitation is a reasonable operational limitation.

5. Penalties

The Fuel Managers Association maintains that there should be no scheduling penalties for changing scheduled receipt and delivery point locations, volumes, and gas delivery, because FT shippers pay SFV rates which already reflect those charges.

Northern Illinois Gas also argues that a pipeline should not be able to impose a penalty if the LDC rearranges its takes among delivery points so long as the takes within an operational zone are equal to confirmed nominations. It states there is no operational reason to tie specific transportation supplies to specific delivery points within an integrated service area.

Appendix C

Issues involving the provisions governing the use of receipt and delivery points, including appropriate penalties, must be addressed in the restructuring proceedings. The purpose of penalties is to inhibit abusive behavior and so they need not be cost based. At the same time, there must be some valid operational reason for imposing penalties on changes in volumes to delivery points within an interrelated service area.

6. Downstream Delivery Points/Upstream Delivery Points

Southwest Gas argues that a shipper should only be able to designate delivery points at the same points or points upstream of the shipper's own delivery points.

The Gas Company of New Mexico argues that the Commission should deny flexible delivery points to all shippers or provide for upstream shippers to have downstream delivery point flexibility, or, if not, make the downstream shippers pay a higher rate to reflect the higher value of their services.

Brymore suggests that the Commission expand delivery point capabilities to include out-of-path points on a secondary basis to expand the value of upstream capacity. Brymore adds that: "Pipelines can (and should) be kept whole by charging an incremental rate to take gas from the most downstream in-path point to the ultimate delivery point. This charge should be equal to the difference in the demand charge components that would be applied to the reassigned capacity plus the difference in the applicable firm commodity rates."[247]

Hadson argues that Order No. 636's language could be read

247. Petition at 17.

as limiting rather than increasing flexibility. Hadson asks the Commission to clarify that firm shippers' rights to flexible receipt and delivery points "include the right to receive gas from any person at any place on the system, and the right to deliver gas to any person at any place on the system[,]"[248] without the limitation on upstream shippers using downstream delivery points.

The Commission adheres to the discussion in Order No. 636 with respect to flexible receipt and delivery points along the mainline; that is, between the place of unbundling, including pooling areas, and the place of primary delivery, *e.g.*, the city-gate or distribution areas. Downstream shippers may designate upstream receipt and delivery points. This is because the downstream shipper is using part of the capacity which it has reserved. However, upstream shippers may not designate downstream receipt and delivery points because they have not reserved or paid for that capacity. If the upstream shipper wants to expand its delivery point capability to include "out-of-path" delivery points, it must obtain that capacity from the pipeline or from another shipper via capacity releasing. But an upstream shipper has no right to downstream capacity solely because it already is a firm shipper.

New England Power argues that shippers with upstream delivery points within a zone should be able to select downstream delivery points within the same zone as well as vice versa. It states that operational concerns can be met by making the downstream service an interruptible service.

The Commission agrees with New England Power that shippers with upstream delivery points within a zone can select

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248. Petition at 14.

downstream delivery points within the same zone and that operational concerns can be met by making service to the downstream delivery point interruptible. This is consistent with the general principle that controls here: a shipper gets flexibility in receipt and delivery points for the part of the system for which it pays a reservation charge. Thus, if a pipeline has zone rates, a shipper gets flexibility within its zone. The appropriate rate for the use of a downstream delivery point within a zone should be addressed in the restructuring proceedings. Hadson argues that shipments "within the [contract] path" should be priced no higher than the FT usage charge for the actual path used. [249] The Commission agrees with Hadson and so clarifies because the usage charge includes only variable costs.

7. Distribution Area Limitation

In Order No. 636, the Commission required pipelines to permit firm shippers to designate flexible delivery points in their distribution areas in the same manner as they designate flexible receipt points in the production areas. Hadson states that the Commission has ignored non-LDC business enterprises that take delivery of gas but have no distribution areas.

The Commission agrees with Hadson and clarifies that it used "distribution areas" in a broad sense, and not as a term of limitation.

8. Section 7(c) shippers

New England Power and Transco argue that shippers receiving transportation service under individual section 7(c) certificates should have the same rights to flexible receipt and

249. Petition at 6.

delivery points as Part 284 shippers. The Commission disagrees. Flexible receipt and delivery points are part of Part 284 transportation. If New England Power (or similarly situated shippers) wants flexible receipt and delivery points, it should convert to Part 284 transportation.

9. Interruptible Transportation

Natural argues that the Commission should permit delivery point flexibility with respect to interruptible transportation. The Commission will permit interruptible transportation flexibility so long as the capacity exists.

10. New Facilities

Southern requests clarification that the flexible delivery point policy of Order No. 636 does not require the construction of delivery point facilities — the "new mandate only refers to available capacity at existing facilities as is the way flexible receipt points are administered on pipelines' systems."[250] Without addressing the merits of any particular case, the Commission clarifies that the flexible delivery point policy by itself does not require the construction of new facilities. However, to the extent pipelines construct new receipt and delivery point facilities, they must do so on a nondiscriminatory basis.

11. Flexible Delivery Points-Pooled Capacity

NIEP asks the Commission to amend the flexible delivery point provisions "to specifically permit such flexibility within the LDCs' pooled capacity, even across pipeline systems. It maintains that LDCs "may need to switch delivery points on a

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250. Petition at 9.

pipeline system, as well as switch pipeline systems, within the pooled arrangement on a periodic basis in order to access changing gas supply services."[251] The Commission regards the right to use of flexible delivery points as applicable only to shippers with capacity on the pipelines. A shipper receives flexibility in its receipt and delivery points for the part of the system for which it pays a reservation charge. Hence, shippers that pool capacity must each arrange for flexible delivery points on the pipelines on which they ship.

12. Bypass

Atlanta Gas asks the Commission to clarify that its discussion of flexible receipt and delivery points in Order No. 636 is not to be read as instituting a mandatory bypass policy for end users to tap into pipelines. The Commission is not instituting a mandatory bypass policy in Order No. 636. But pipelines must permit end users with firm transportation rights under Part 284 to use flexible delivery points.

13. Exemption

Southwest Gas asks the Commission to expressly exclude El Paso from any flexible delivery point requirement because under El Paso's system of operation, there is insufficient basis owing to constraint points to adopt a flexible receipt point policy. The Commission believes that issues involving El Paso's constraint points and flexible delivery points must be addressed in El Paso's restructuring proceeding.

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251. *Id.*

Appendix C

I. Curtailment

Several of the parties in their rehearing requests contend that Order No. 636 is in error in not requiring that capacity allocations during periods of capacity curtailment be implemented on an end-use rather than on a *pro-rata* basis.[252] Generally, these parties argue that the high-priority, end-use categories established by Title IV of the Natural Gas Policy Act (NGPA),[253] apply to capacity curtailments as well as supply curtailments. APGA, Brooklyn Union, the Fertilizer Institute, the State of Michigan, Rochester Gas, and Washington Gas maintain that the operative statutory language in Title IV applies to curtailment of all natural gas "deliveries" and does not distinguish between the curtailment of deliveries caused by supply shortages as opposed to the curtailment of deliveries caused by capacity constraints. APGA argues that Congress did not specifically apply the Title IV priorities to capacity curtailments because pipeline services at the time of enactment of the NGPA were bundled. Similarly, Rochester Gas contends that the NGPA was passed in a different regulatory environment and while the Commission has changed the regulatory scheme, this does not eliminate the Congressional intent expressed in Title IV that deliveries of gas to high-priority end-users be protected during curtailment. APGA, Citizens Gas, Rochester Gas and Washington Gas further maintain that mandatory unbundling of pipeline sales service combined with *pro-rata* capacity curtailment results in a degradation of service by depriving pipeline sales customers of their Title IV curtailment priority in the event of a capacity curtailment.

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252. APGA, Brooklyn Union, Cincinnati Gas, Citizens Action, Citizens Gas, the Fertilizer Institute, the State of Michigan, Rochester Gas, and the Washington Gas Light Company (Washington Gas).

253. 15 U.S.C. §§ 3391-94.

APGA, Brooklyn Union, the Fertilizer Institute, and Washington Gas further argue that Title IV was enacted as a result of Congressional concerns over the effects of natural gas cut-offs to agricultural and other high-priority users and that from the end-user's standpoint supply and capacity curtailments are the same in their effects. Thus, these parties conclude that the Congressional concerns regarding supply cut-offs pertain equally to capacity caused cut-offs and that Congress intended that Title IV apply equally to supply and capacity curtailments. APGA also argues that Congress in Title IV required the Commission to protect high-priority users to the "maximum extent practicable" and that such policy applies equally to capacity and supply curtailment. Brooklyn Union further asserts that it is illogical to conclude that Title IV does not apply to the new national transportation network fostered by other sections of the NGPA.

The Commission is not persuaded by these arguments to depart from its interpretation of the inapplicability of the Title IV end-use priorities to capacity curtailments. The Commission has interpreted Title IV of the NGPA in this manner since the enactment and initial implementation of the NGPA[254] and since that time has consistently reiterated its position that Title IV applies only to curtailment by pipelines of natural gas deliveries caused by supply shortages.[255] Furthermore, the Commission has also consistently rejected arguments similar to those advanced by the parties in this proceeding to the effect that Title

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254. *See, e.g.*, Order No. 29-C, FERC Stats. & Regs., Regulation Preambles 1977-1981, ¶ 30,092 (1979).

255. *See, e.g.*, Order No. 436, FERC Stats. & Regs., Rep. Preambles 1982-1985, ¶ 30,665 (1985).

IV applies to both capacity and supply curtailments.[256] Moreover, we believe that more recent expressions of Congressional intent regarding the structure and operation of the natural gas industry, *i.e.*, the Decontrol Act,[257] support the Commission's curtailment policies as expressed in Order No. 636.

Again, it is the Commission's view, based upon the language of the NGPA itself, the circumstances surrounding the enactment of the NGPA, the legislative history of the NGPA and subsequent court opinions that application of the Title IV end-use priorities to capacity curtailments (that is, transportation) was neither intended nor envisioned by the Congress. First, it is beyond dispute that the NGPA was enacted to remedy the natural gas supply shortages facing the nation which became critically apparent in the mid-1970's.[258] Title I of the NGPA was intended to provide investors with adequate incentives to develop new sources of gas supply. Title II of the act was intended to ameliorate the immediate impact of these incentive prices on certain classes of natural gas users. Title III of the Act was intended to break down the existing barriers between the interstate and intrastate natural gas markets, so that formerly intrastate natural gas supplies could flow freely into the national market place to alleviate the natural gas shortage in the interstate market. In addition, Title III vests in the President a broad array of powers to respond to natural gas *supply* emergencies. In sum, the policy provisions of the NGPA were all enacted in response

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256. *See, e.g.*, Order No. 29-C, *supra*; Order No. 436-A, FERC Stat. & Regs., Regulation Preambles 1982-1985, ¶ 30,675 (1985).

257. Pub. L. No. 101-60, 103 Stat. 157 (1989).

258. *See, e.g.*, Process Gas Consumers Group v. United States Department of Agric., 694 F.2d 728, 738 (D.C. Cir. 1980).

to the need to increase the *supply* of natural gas available to fill the nation's energy needs. On the other hand, the issue of pipeline capacity constraints was not part of the Congress' remedial action in its enactment of the supply-oriented NGPA. It is in this context that the petitioners' arguments regarding the intended scope of the applicability of Title IV must be viewed.

The petitioners' major argument is that the operative language of Title IV speaks in terms of "deliveries" of natural gas, *i.e.*, "curtailment of deliveries for such use,"[259] and that no specific distinction between curtailment of deliveries due to supply shortages and those due to capacity constraints is made. It is our view that, in the light of the immediate purpose of the NGPA to provide incentives to prevent gas supply shortages, the petitioners read into the term "deliveries" an application that was not intended by the Congress. At the time the NGPA was enacted, the curtailment plans on file with the Commission generally governed only pipeline sales curtailments resulting from gas supply shortages, not capacity limitations. This resulted from the fact that the Federal Power Commission's (FPC) curtailment policies and regulations from their inception were intended to deal with the "allocation of priorities and rationing of this limited supply of natural gas" available to be sold by interstate pipelines occurring during "gas shortages".[260]

Under the FPC curtailment rules, interstate pipelines were only required to file supply curtailment plans covering natural gas sales and were not required to file capacity curtailment plans

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259. *See, e.g.*, 15 U.S.C. §§ 3391(a), (a)(1).

260. Louisiana Power and Light Co. v. FPC, 483 F.2d 623,626 (5th Cir. 1973). *See* also, Pacific Gas & Electric Co. v. FPC, 506 F.2d 33,35 (D.C. Cir. 1974); State of North Carolina v. FERC, 584 F.2d 1003,1007 (D. C. Cir. 1978).

covering transportation. Moreover, the FPC's policy statements requiring pipelines to file these sales curtailment plans, like the NGPA, also used the operative term "deliveries" as opposed to "sales" or "transportation".[261] Thus, it is likely that the choice of the operative term "deliveries" in Title IV was chosen to correspond to the same operative term found in the existing FPC required supply curtailment plans. This view is in accord with the stated intent of the Congress that for purposes of implementing Title IV "the Commission is instructed to reopen curtailment plans that are already in effect under the NGA only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule."[262] Had Congress intended also to cover gas only transported by the pipelines or to cover capacity curtailments, then nearly all of these plans would have had to be reopened.

Further, the broad term "deliveries" covers sales for resale as well as transportation for direct sale, both circumstances subject to the FPC's curtailment jurisdiction and pipeline curtailment plans. Moreover, this view of the use of the term "deliveries" is also in accord with Congressional statements of its understanding of the definition and purpose of curtailment plans as expressed in the legislative history of related energy legislation, *i.e.*, the Public Utilities Regulatory Policies Act of 1977.[263] As stated in *Process Gas Consumers v. United States Dept. of Agriculture*:

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261. *See, e.g.*, Order No. 467, 49 FPC 85 (1973) ("priorities-of-deliveries by jurisdictional pipelines during periods of curtailment"), Order No. 467-B, 49 FPC 583 (1973) ("initial priorities to be followed by jurisdictional pipeline companies during periods of curtailed deliveries").

262. Joint Explanatory Statement of the Committee of Conference, Title IV, Section 401, I FERC Stats. & Regs. ¶ 3101 at p. 3121 (1978).

263. Pub. L. No. 95-617.

Appendix C

Since the advent of natural gas scarcities in the early seventies, regulated interstate pipelines have been required to establish elaborate curtailment plans detailing which of their customers will get how much gas in what priority in times of short supply. In Congress' own words:

> Curtailment plans establish priorities for the delivery of natural gas when supplies are insufficient to meet contract demand. . . .
>
> H.R. Rep. No. 1750, 95th Cong., 2d Sess. 112-13 (1978), U.S. Code Cong. & Admin. News 1978, p. 7846.[264]

Thus, as the agency charged with interpreting the NGPA, the Commission remains of the opinion that in enacting Title IV, the Congressional intent was to assure that gas supplies for essential agricultural and the other specifically enumerated high-priority end-users would be afforded the highest priorities in then existing pipeline supply curtailment plans in the event of a shortage of the gas supplies sold by interstate pipelines. The Commission further believes that it would be in error for it to infer that if Congress had in fact addressed and considered the then hypothetical issue of capacity curtailments, Congress would have mandated the same end-use curtailment method to be applied to capacity curtailments as that envisioned for supply curtailments. As indicated below, capacity curtailments present problems and issues distinct from those presented by supply

264. 694 F.2d. 728, 772 (D.C. Cir 1980) (Wald, dissenting on other issues).

curtailments in the context of unbundled, open access transportation, and in the Commission's judgement are not suited to resolution by imposition of end-use priorities.

The petitioners present a literal reading of Title IV of the NGPA, viewed apart from the legislative history, contemporaneous industry conditions and historical context in which it was enacted. Even if this view can be squared with a plausible application of the literal words of the statute, the Commission does not believe it can be reconciled with the context in which the NGPA was enacted or with more recent expressions of Congressional intent. For instance, the petitioner's contention that the Title IV end-use priorities apply to pipeline capacity curtailments creates a conflict with the more recent expression of Congressional intent embodied in the Decontrol Act. The Decontrol Act "finished off" the then already nearly complete natural gas decontrol process initiated in the NGPA.[265] The Decontrol Act expresses Congressional recognition of a completion of the "transition from the highly controlled, shortage-beset gas industry . . . to today's substantially decontrolled market."[266] It also recognizes the creation by the Commission of "a competitive gas purchasing and transportation market," which in the opinion of Congress would minimize the instability in the natural gas markets which was characteristic of what the Congress acknowledged as being an antiquated regime of stringent regulatory controls.[267] The Congress further found that the Commission's open-access pipeline initiatives had created more competition in the interstate pipeline industry

265. H. Rep. No. 29, 101st Cong. 2d Sess., at p. 2 (1989).

266. *Id.* at 3.

267. *Id.*

and had brought lower prices to all consumers, including captive residential consumers.

Thus, while the Decontrol Act did not deregulate gas pipelines, the Act is a clear endorsement of the benefits of a pro-competitive regulatory scheme for national gas supplies. Moreover, the Congress in enacting the Decontrol Act expressed its strong belief that the Commission's "current competitive open-access pipeline system [be] maintained" to ensure that captive customer's are not disadvantaged".[268] An integral part of the Commission's "current open-access" pipeline system was that firm, open-access transportation was not *required* to be allocated on a Title IV type end-use basis in the event of curtailment.[269] In addition, the Commission believes that the complexities inherent in end-use capacity curtailment plans and the fact that the Commission has never required capacity curtailments to be implemented on an end-use basis would, if

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268. *Id.* at 4.

269. *See, e.g.*, Order No. 436-A; *supra*, FERC Stats. & Reg. Preambles (1982-85) at p. 31,652. While the Commission has required open-access transportation to be curtailed on a *pro-rata* basis, the Commission has approved settlements which also provide differing degrees of end-use allocation. *See, e.g.*, Northwest Pipeline Corp., 39 FERC ¶ 61,109 (1983) (permitted establishment of curtailment priority for essential agricultural and high-priority uses in the absence of adverse comments); Florida Gas Transmission Co., 51 FERC ¶ 61,309 (1990) (curtailment by end-use permitted); United Gas PipeLine Co., 49 FERC ¶ 61,006 (1989) (end-use emergency relief permitted in context of a settlement). Curtailment issues must be considered in the RS proceedings and the parties in the RS proceedings may agree upon similar arrangements if they can be implemented in accordance with the restructured services of a particular pipeline. For the Commission to *require* such arrangements for all pipelines, however would severely undermine the principles of unbundled, open access transportation.

ordered generically, impose a significant regulatory burden. Thus, in the Commission's judgement the curtailment policies set out in Order No. 636 represent a proper reconciliation of the requirements of Title IV of the NGPA, the more recent statements of Congressional purpose expressed in the enactment of the Decontrol Act, and the policies underlying Order No. 636.

APGA, Brooklyn Union, and Citizens Gas also argue that not applying end-use priorities to capacity curtailment is inconsistent with the NGA and past Commission policy prior to the enactment of the NGPA. These parties contend that under the NGA the Commission's policy was that end-use curtailment was necessary because private contracts do not necessarily serve the public interest and that the rationale for protecting high-priority customers under the NGA is the same today as it was before. Citizens Gas maintains that the NGA requires assurance of reliable service to high-priority end-users. APGA similarly contends that the public interest under the NGA requires that high-priority end-users be protected from curtailment.

The Commission disagrees with the notion advanced by these parties that because in the 1970's the FPC found that the allocation of scarce gas supplies during curtailment was required to be based upon end-use principles, rather than private contractual arrangements, in order to protect the public interest that the Commission in the 1990's is now restricted to requiring an end-use methodology as the industry's exclusive allocation methodology during both supply and capacity curtailments. First, while it is correct, as the petitioners point out, that the courts have approved end-use as an appropriate consideration for purposes of pipeline supply curtailments,[270] the NGA does not

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270. *See, e. g.*, State of North Carolina v. FERC, *supra* 584 F.2d at 1012.

require that allocations of either supply or capacity during curtailment be made exclusively on the basis of end-use principles. Moreover, in the light of the changes in both the regulatory and legislative environment, as well as changes in the natural gas industry which have transpired since the 1970's, as discussed above, the Commission believes that the exclusive reliance on an end-use allocation methodology is not required to protect the public interest. The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers, storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (*e.g.*, local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options. In addition, natural gas market conditions are now very different from the 1970's. In contrast to the chronic supply shortages of the 1970's, capacity and supply disruptions in the 1990's, if they occur at all, are likely to be infrequent and short-lived, largely as a result of the changes initiated by the provisions of the NGPA other than Title IV and the Commission's policies in Order Nos. 436 and 636.

Given the growing array of unbundled service options, which will be further promoted by Order No. 636, customers are increasingly free to choose different mixes of firm and interruptible pipeline services as well as different sellers, different receipt points, and different market centers or aggregation points. In making such choices, each customer will

assume different price and reliability risks. Requiring the generic allocation of pipeline capacity on the basis of end-use rather than *pro rata* based upon each customer's contractual choices would tend unfairly to protect those who took risks at the expense of customers who have undertaken the planning and greater cost of proceeding cautiously. Such a result would be neither just nor reasonable nor consistent with the unbundled, market-oriented gas industry, which both the Congress and the Commission have been encouraging. Accordingly, the Commission finds that neither the NGA nor the public interest require that the Commission on an industry wide basis today extend the end-use curtailment rules applicable to pipeline sales to interstate pipeline transportation, storage, or other services.

APGA, Laclede Gas Company (Laclede), and the State of Michigan argue that the issue of capacity curtailment methodologies aside, Order No. 636 does not adequately provide curtailment protection from supply shortages to high-priority end users. These parties contend that Order No. 636 defeats the purpose of the NGPA Title IV priorities during times of natural gas shortages. APGA and Laclede maintain that given the possibility of a failure of third-party gas supplies, reliance on third party sales makes protection from supply shortages difficult and that market based pricing will not adequately protect high priorities from supply shortages. Laclede argues that the Commission should require that a plan be in place to insure gas availability to high priorities in the event of a shortage in supply.

We disagree with these assertions that Order No. 636 fails to protect high-priority users from supply shortages. The Commission is of the view that the best protection from the specter of a future natural gas supply shortage is the promotion of an open and competitive wellhead market where all natural

gas suppliers are able to compete for gas purchasers on an equal footing, unhindered by the possession of any undue competitive advantage by any class of suppliers. By fostering this goal, Order No. 636 aims to ensure that the benefits of wellhead decontrol, including helping "to ensure adequate supplies of reasonably priced gas in the future"[271] will redound to the benefit of consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act.

Congress' judgement was that the best protection against, and remedy for, supply shortages was to allow the market to establish the price for gas. If supplies tighten, the price can rise which will stimulate new investment to bring new supplies to market. Since Congress mandated this course, beginning with the enactment of Title I of the NGPA, the industry has not experienced shortages beyond isolated, short-lived dislocation. By eliminating the undue competitive advantage inherent in pipeline bundled sales services and by establishing a pipeline rate structure under which all gas merchants will be able to compete in a national market without regard to fixed transportation costs included in usage charges, Order No. 636 will help to achieve Congress' intent in passing the Decontrol Act to "over time force the evolution of a set of lowest-cost producers" which "will yield lower prices and more abundant supplies".[272] Moreover, as we discussed above in regards to capacity curtailments, we believe that the imposition of the industry-wide, end-use supply curtailment scheme envisioned by the petitioners would be inconsistent with the market-oriented policies espoused by the Decontrol Act and given foreseeable supply conditions, would be an unnecessary regulatory burden.

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271. S. Rep. No. 39, 101st Cong., lst. Sess., at p. 2 (1989).

272. H.R. Rep. No. 29, *supra*, at p.7.

Finally, in the event of an unexpected and sudden *force majeure* supply shortage, Title III of the NGPA vests in the President ample authority to effectively assure that available gas supplies are allocated and transported to meet critical needs.

Several parties[273] assert the position that the Commission's direction to the parties, to negotiate and develop voluntary plans to deal with emergency shortages due to capacity constraints in the restructuring proceedings, is an abdication of the Commission's statutory responsibilities. APGA and State of Michigan argue that LDC's should not be penalized by having to pay high amounts to lower priority customers in order to be assured of being able to serve their high-priority loads. APGA, Citizens Action, and the State of Louisiana argue that the Commission must require that all pipelines include in their compliance filings an emergency exception from their *pro-rata* curtailment plans to provide gas to residential and small commercial users and to protect life and property in the event of curtailment. The Industrial Groups assert that all pipelines should implement plans to allow their customers to offer voluntary release of capacity for compensation during emergency situations. APGA further maintains that contractual provisions are an inadequate method for protecting human needs customers and other high-priority end users. In addition, the Industrial Groups state that while it supports *pro-rata* curtailment, that the Commission should prescribe specific allocation procedures rather than leaving the parties to negotiate such procedures. The State of Michigan also avers that the Commission has failed to explain the basis of the assertion in Order No. 636 that gas will continue to flow for heating without regard to *pro rata* curtailment plans.

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273. APGA, Brooklyn Union, Cincinnati Gas, State of Michigan, and Rochester Gas.

Appendix C

The arguments of the petitioners that object to developing curtailment plans and negotiating plans to implement voluntary contractual emergency supply and transportation arrangements in the restructuring proceedings are grounded on an incorrect premise, *i.e.*, that the NGPA and/or the NGA mandate that the Commission establish a specific set of procedures for end-use allocations applicable to all pipelines. As discussed above, in the Commission's view, this assumption is not accurate.

Order No. 636 allows the pipelines and their customers to develop a capacity curtailment plan in the restructuring proceedings under the general guideline that the result of such negotiations must be a tariff that sets out the pipelines' supply and capacity curtailment plans in sufficient detail to accommodate the interests of all shippers. The Commission believes that this is in accord with the principles underlying both the NGA and the NGPA. Moreover, such negotiated curtailment plans will result in systems of allocation and the development of voluntary, mutually beneficial, emergency contractual programs and procedures that are best tailored to the individual pipelines and the needs of their customers as expressed in the economic value, *i.e.*, price, which they are willing to pay either to the pipeline itself or, under private contractual arrangements, to other pipeline shippers, to assure that their demand for capacity on the pipeline will be satisfied in the event of curtailment. In this regard, the Commission endorses the suggestion of the Industrial Groups that pipelines include as part of their compliance filings plans to allow their customers to offer voluntary release of capacity for compensation during emergency situations, and encourages the development of similar suggestions which have been made in this proceeding.[274]

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274. *See, e. g.*, Technical Conference Tr. at 282-83.

Finally, as the State of Michigan points out, the Commission does expect that gas will continue to flow to those who need it for heating or other important needs, notwithstanding a pipeline's *pro rata* curtailment plan. The Commission's expectation is based on experience since the implementation of the NGPA, which shows that gas has always flowed according to the dictates of the market, *i.e.*, to the heat sensitive users who need it most and who are thus willing to pay the prevailing market price for it. It is because the Commission expects that these historical market forces will continue to direct gas supplies and capacity to heating and other important uses, that we have urged the parties to develop flexible tariff mechanisms, whether in the nature of special relief with compensation, voluntary contractual arrangements or some other device, which will allow pipelines and their customers in planning their operations to take into account and provide mechanisms for dealing with these contingencies.

Elizabethtown expresses the view that Order No. 636 should require customers receiving more than a *pro rata* share of pipeline gas during periods of shortage to pay compensation to customers who receive less than a *pro rata* share as a consequence. Rochester Gas maintains that compensation schemes can be developed in the pipelines' restructuring proceedings which can compensate low priority users whose gas is lost to high-priority users as a result of curtailment. In addition, Elizabethtown contends that Order No. 636 should require that a pipeline sales customer exhaust all of its alternative sources of supply before being eligible to receive a pipeline's sales gas supply under its curtailment priority.

The Commission's position on curtailment compensation plans is that the parties in the individual restructuring proceedings must explore the development of such schemes as

those suggested by Elizabethtown and Rochester Gas in the context of developing their individual curtailment plans and in the development of voluntary emergency contractual arrangements between shippers. However, the Commission believes that it would be contrary to the concept of the restructuring proceeding process and the negotiation and development of individually tailored curtailment allocation procedures and emergency mechanisms for it to mandate a generic compensation scheme. In addition, in its request for rehearing, Elizabethtown has not presented any argument to persuade the Commission to change its position that it is not appropriate to require high priority customers to exhaust other sources of gas supplies before being entitled to receive more than a *pro-rata* share of available pipeline supplies by application of the NGPA Title IV priorities to pipeline sales.

Tenneco claims that the provisions of Order No. 636 requiring parties in the restructuring proceedings to fashion their own curtailment plans constitutes an effective change in prior curtailment plans and policy which requires the preparation of an Environmental Impact Statement (EIS) prior to issuance of the Order.

The Commission is of the opinion that the issuance of the curtailment related provisions of Order No. 636 does not require the preparation of an EIS. First, the Commission has not changed its curtailment policies. Under Order No. 636, as before, pipeline sales during supply curtailments, if they occur, will be implemented according to end-use allocation methodologies which include the Title IV priorities. Similarly, as they were under Order No. 436, capacity curtailment plans will generally be developed according to *pro-rata* allocation methodologies with the allowance of end-use measures to provide for emergencies. Furthermore, under the Commission's application

of section 380.5(b)(5) of the Commission's Regulations[275] only new natural gas supply curtailment plans, or any amendment to an existing supply curtailment planthat has a major effect on an entire pipeline system has been subject to an environmental assessment. Thus, any determination regarding the necessity of an EIS for any particular pipeline's supply curtailment tariff compliance filing would at this time be speculative and premature.

Finally, Elizabethtown and Tenneco argue that unbundled pipeline sales should not be subject to the Title IV end-use curtailment priorities, but should be treated as all other gas sellers. Elizabethtown contends that the application of sales curtailment to pipeline sales makes pipeline sellers a less reliable supply source. Tenneco contends that Order No. 636 unduly discriminates against pipeline merchants by requiring only pipelines to follow end-use curtailment plans. In the alternative, Tenneco maintains that end-use sales curtailment should not apply to pipeline marketing affiliates.

The Commission agrees with the arguments advanced by Elizabethtown and the observation of Tenneco that for curtailment purposes unbundled pipeline sales should be treated as all other gas sales. However, as the Commission stated in *Transcontinental Gas Pipe Line Corp.*,[276] "[u]ntil Congress changes the [NGPA], the statutory priority [for pipeline sales] must be observed."[277] Thus, Title IV of the NGPA must continue to apply to pipeline sales only. For the same reason, the

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275. 18 CFR 380.5(b)(5).

276. 57 FERC ¶ 61,365 (1991).

277. *Id.* at 62,117.

Commission agrees with Tenneco that end-use sales curtailment does not apply to pipeline marketing affiliates.

VI. TRANSPORTATION RATES

In Order No. 636, the Commission concluded that the modified fixed variable (MFV) method of cost classification "is not in the public interest, unreasonably hinders competition among gas sellers, and is unjust and unreasonable under NGA Section 5."[278] The Commission adopted SFV in lieu of MFV so that "all gas merchants would be able to compete in a national market without regard to fixed transportation costs included in the usage charge."[279] This competition will "maximize the benefits of wellhead decontrol by increasing the nationwide competition among gas merchants (including pipelines)."[280] Further, "[t]his merchant-to-merchant competition should help to achieve Congress' intent in enacting the Decontrol Act to "over time force the evolution of a set of lowest-cost producers" to "yield lower prices and more abundant supplies" to the benefit of all consumers of gas.[281]

The Commission recognized that the shift to SFV, without any adjustments, could result in cost shifting among customer classes. Hence, the Commission directed that pipelines adopt measures to mitigate cost shifts if the use of SFV will result in a 10 percent or greater increase in revenue responsibility for

278. Order No. 636 at p. 30,434.

279. *Id.*

280. *Id.*

281. *Id.*, *quoting*, H.R. Rep. No. 29, *supra*, at p. 7.

any historic customer class. These mitigation measures are to phase-in any such rate increase over no more than a four year period. The Commission set forth several potential phase-in methods, including the use of a one-part volumetric rate for small customers.

Last, the Commission provided that the determination of rates for interruptible transportation would still be governed by the principles enunciated in the Rate Design Policy Statement.

As discussed below, the Commission is granting rehearing with respect to the designing of rates for small customers. The Commission is retaining SFV for rate design (billing) and cost allocation purposes but will require the use of different ratemaking techniques to distribute revenue responsibility among customers if significant cost shifts occur among pipeline customers, as discussed below, as a result of allocating fixed costs only on the basis of peak entitlements.

A. Rehearing Requests Concerning SFV

A number of petitioners object to the Commission's reasoning in adopting SFV. In brief, they argue that the Commission has rested its decision on invalid goals, has not supported its finding that MFV is not in harmony with those goals if they are valid, and has not supported its finding that SFV is lawful.

As discussed more fully below, the Commission rejects petitioners' contentions. First, as stated above, the Commission is mandating the SFV rate design method for billing (unless the Commission permits otherwise under the exception in 18 CFR 284.8(d)). The Commission believes that its analysis and

conclusions in Order No. 636 comport with its responsibility under the NGA to adopt cost classification methods to achieve goals that are pertinent to current conditions. This requires that the Commission use its judgment to "make the pragmatic adjustments which may be called for by particular circumstances."[282] The Commission must exercise its judgment and discretion in light of the prevalent market, economic, and industry circumstances. Hence, a particular distribution of fixed costs between the reservation and usage charges is not inviolate.[283] And, indeed, as chronicled in Order No. 636, the Commission has changed its goals as market conditions have changed over time.[284] The Commission sees no reason in petitioners' arguments for modifying its conclusions in Order No. 636 to adopt a cost classification method that does not impede the operation of the competitive national wellhead market underlying and envisioned by the Decontrol Act, that MFV does not perform that function but rather hinders achieving that goal, and that simply put, SFV is rationally connected to the Commission's goal of achieving an efficient national gas market which will yield reasonable gas prices to benefit gas consumers and which will send proper market signals to maintain adequate gas supplies.

It is true, as also discussed below, that the adoption of SFV in lieu of MFV may well shift costs among different classes of customers and within classes of customers. However, the Commission concludes that petitioners have not shown any undue harm. First, the Commission is providing for mitigation

282. FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942).

283. Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176 (D.C. Cir. 1975).

284. Order No. 636 at pp. 30,432-33.

measures to accompany the move to SFV. Second, the Commission has adopted a means for firm customers to shed unwanted firm capacity to those seeking capacity during the restructuring proceedings and thereafter under the capacity reallocation mechanism of section 284.243 of the regulations. Third, the Commission, as discussed below, does not believe that the cost shifts to individual residential gas consumers will be undue in aggregate amount in light of the goals of SFV.

B. Rationale

1. Validity of Goals

The APGA argues that "the Commission's desire to develop a 'competitive, national gas market,' promote competition among gas merchants, and ensure that gas is shipped on even terms are not legitimate rate design goals."[285] It maintains those goals rest outside of the Commission's role because the production end of the natural gas industry is virtually deregulated. The APGA further contends that even if those goals are valid, the Commission may seek to achieve them only subject to its primary responsibility of protecting consumers from the exercise of monopoly power by pipelines. Similarly, Southern California Gas Company (SoCal Gas) maintains that it cannot accept the notion that the Commission has the duty or obligation under the NGA to increase producers' profits at the wellhead, especially after decontrol. Peoples Natural Gas argues that the Commission erred in not applying antitrust law in analyzing the lawfulness of MFV.

The Commission rejects APGA's arguments about the legitimacy of the Commission's goals with respect to rate design.

285. Petition at 80.

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The Commission's interest in the production end of the natural gas industry has not been eliminated by the virtual decontrol of natural gas first sales. True, the Commission has no authority over wellhead gas prices. However, the Commission is still responsible for ensuring that, over the long-term, consumers have access to an adequate supply of natural gas at reasonable prices. It is beyond doubt that the Commission has the authority to regulate pipelines in a manner that fulfills that responsibility. That authority includes the establishing of just and reasonable transportation rates that maximize the benefits of decontrol to gas consumers. The Commission further believes that the rate design goals of Order No. 636 fully comport with the Commission's primary responsibility to protect gas consumers and rejects contentions that it has acted to increase producers' profits. Last, the Commission must apply the antitrust law in analyzing cost classification and rate design methodologies in light of its goals under the NGA. The Commission is not required to analyze rate design, competition, or their relationship under the standards of the antitrust laws.[286]

2. Lawfulness of MFV

Petitioners object to the Commission's conclusion that MFV is unjust and reasonable. The Commission observes that the essence of their objection is to the elimination of MFV as a cost classification method for the purpose of allocating costs among customers rather than to the use of SFV for billing purposes only. If there otherwise would be significant cost shifts, the Commission will require the parties in the restructuring proceedings to develop ratemaking methods that result in a distribution of revenue responsiblity that reflects different

286. *See supra* on the antitrust laws and Transwestern Pipeline Co. v. FERC, 820 F.2d 733 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988).

customer load profiles so long as SFV is used for billing purposes.[287] For example, seasonal contract quantities (*i.e.*, seasonal entitlements or CDs) may be used to apportion revenue responsiblity among customers. As a general matter, the Commission discourages the creation of customer classes for various transportation services other than the special small customer class provided for in this rule.

The APGA, the Coalition Against Straight Fixed Variable (Coalition), Memphis Light, ConEd, the City of Hamilton!, Ohio (Hamilton), NYSE&G, Northern Illinois Gas, the New England Gas Distributors, the State of Michigan, and Southwest Gas argue that the Commission's conclusion that MFV is unjust and unreasonable because it is not in harmony with the Commission's goals, is unsupported by empirical analysis and is based on faulty assumptions. In particular, they attack, as unsupported, the Commission's conclusion that the shipment of gas on uneven rate terms will inhibit the development of a national gas market by distorting wellhead prices. In particular, the petitioners argue that the following Commission example is unsupported:

> For example, producers in different fields that compete for the market share via different pipelines will often have their competitive positions in that market affected by the amount of fixed costs in the pipelines' respective transportation usage charges and not by the producers' own costs and efficiencies in producing gas.[288]

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287. In other words, the Commission clarifies that using SFV does not foreclose the parties from developing one-part reservation charges based on both annual and peak demand considerations.

288. Order No. 636 at p. 40,434.

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Petitioners maintain that the Commission has not shown that multiple pipelines serve a given market,[289] that, as with other industries, there is no reason why natural gas wellhead markets should not be affected by their location in relation to consuming markets,[290] that shippers expect rates on different pipelines to be different,[291] that gas purchasers make their purchasing decisions on a total delivered cost analysis,[292] that competition has flourished under MFV as shown by the current low wellhead price of gas,[293] and that MFV cannot be anticompetitive because transportation rates will be the same for all shippers, including the pipeline's sales division.[294]

The Commission adheres to its conclusion that MFV is unjust and unreasonable when used widely as a billing method because of its adverse impact on the development of a national and competitive gas market. Under MFV, or any method other than SFV, pipeline usage charges vary depending upon the amount of fixed costs recovered in the usage charge. If customers can choose to take gas from two or more pipelines, they will minimize their transportation costs by baseloading the pipeline with the lowest usage rate and swinging on pipelines with higher

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289. *E.g.*, NYSE&G.

290. *E.g.*, Northern Illinois Gas, Alabama Gas, Peoples Natural Gas similarly argues that shippers expect rates on different pipelines to be different.

291. *E.g.*, Peoples Natural Gas, Southwest Gas.

292. *E.g.*, Cincinnati Gas, the State of Michigan, Hamilton.

293. *E.g.*, CPUC, SoCal Gas.

294. *E.g.*, ConEd, Southwest Gas, Peoples Natural Gas.

usage rates. Pipelines with low usage rates consequently would tend to have higher load factors (enabling them to lower their usage charges even further) as compared to pipelines with more fixed costs in their usage charge. Producers whose gas moves to market over pipelines with low usage charges would be able to have higher sales and/or higher prices than otherwise equally efficient producers whose gas moves over pipelines with higher usage charges. Equally efficient producers whose gas gets to market on pipelines with equal total cost would not be on an equal footing because of the differing rate designs of the pipelines. This is inefficient and creates artificial barriers to the production of gas from one basin as compared to another.

A study done by the Commission staff in 1984, of the number of LDCs connected to mutiple pipelines, showed that, as of 1980, 431 out of 1,443 LDCs surveyed, or 30%, were served by more than one pipeline.[295] On average this subgroup was served by 3.6 pipelines. Since then the trend has been for LDCs to develop more connections to multiple pipelines.

It is important to emphasize that the goal is a national gas market in which efficient, lowest cost producers will flourish and compete.[296] The Commission believes that "[c]ompetition among this set of efficient producers will yield lower prices and more abundant supplies, than will competition among a group of less efficient higher-cost producers."[297] In addition, the

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295. David Mead, "Concentration in the Natural Gas Pipeline Industry," FERC Staff Working Paper (1984).

296. H.R. Rep. No. 29, 101 at Cong., 1st Sess. at p. 7 (1989) (Decontrol Act).

297. *Id.*

Commission believes that fixed costs in pipeline usage charges inhibit the sending of accurate price signals "at the margin" because the inclusion of those costs in the delivered price of day-to-day gas purchases does not allow producers and consumers to see the marginal price of gas that over the long run is more likely to produce the Commission's goal of an efficient national gas market.

This goal is a national goal and not a local goal of producing sets of efficient producers in one production area without regard to efficiency in other production areas throughout the country. Hence, this national concern vitiates the usual approach where the location of supply is relevant to the ability to compete in consuming markets. The Commission is concerned with the impact of multiple pipeline rates on multiple production areas. An efficient national market requires the actual cost of transportation to be reflected in the delivered prices of the gas, and MFV distorts unit delivered prices.

The Commission also believes that its analysis in Order No. 636 is in harmony with opening up the national pipeline grid to all consumers of gas. The essential point is that multiple producing areas and consuming markets have access to each other, even if the producing areas and consuming markets are each served by a single pipeline, but not the same pipeline. In addition, this multiple access should be enhanced by the programs and policies promulgated by Order No. 636. The new flexible delivery point policy, the new capacity reallocation mechanisms, and the recognition of the role of market centers should further open up the pipeline grid to form a national gas market for the meeting of all gas sellers and gas purchasers in the most efficient manner.

The Commission recognizes that gas purchasers use a total

delivered cost analysis to make a decision with respect to entering into new long-term contractual arrangements with pipelines and gas merchants. Some LDCs (such as Brooklyn Union, Cincinnati Gas, and SoCal Gas) are served by more than one pipeline and can purchase gas from different producers with whom they have long-term or spot market arrangements. In making decisions about long-term supply arrangements, it will always be cheaper for LDCs with multiple pipeline connections to baseload the pipeline with the lower usage rate and swing on the pipeline with the higher usage rate. This will affect the long-term contracting decisions of these LDCs both as to the amount of capacity reserved on each pipeline and the long-term gas supply contracts with producers connected to each pipeline. In short, differing usage charges will bias long-term decisionmaking as well as short-term decisionmaking.

The Commission reaffirms its conclusion that MFV rate design is unjust and unreasonable as discussed in Order No. 636. Simply put, MFV rate design hinders, and will continue to hinder, in the unbundled environment created by Order No. 636, and competition by gas sellers in a national gas market based upon their efficiencies, undistorted by varying fixed costs in pipeline usage charges.

APGA and Peoples Natural Gas argue that the Commission erred in stating that continuation of MFV will bias pipeline debt-equity ratios. The Commission's statement that "MFV could bias the debt—equity ratio because pipelines can increase their debt component to lower their usage charges" [298] was an observation of what might happen and was not relied on in finding MFV unjust and unreasonable.

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298. Order No. 636 at p. 30,433.

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3. Lawfulness of SFV

Petitioners raise several arguments in opposition to SFV. First, Southwest Gas, and Peoples Natural Gas argue that there is no evidence of record to support the Commission's conclusion that SFV will result in the shipment of gas under even terms since each pipeline's costs are different, as the Commission recognized in *Iroquois Gas Transmission System.*[299]

It is true that there are many reasons why pipelines may have rate differentials. The purpose in adopting SFV is to minimize the differentials in the usage charge by shifting fixed transmission and storage costs to the reservation charge. The remaining usage charge, (primarily, to cover fuel costs) is small enough that its impact is insignificant on the Commission's goal.

Hamilton maintains that "[u]ntil the market effects of the service restructuring ordered by the Commission are experienced, and the resulting level and efficiency of competition among gas sellers known, the Commission cannot possibly know whether generic application of SFV is necessary, or even useful, in the promotion of competition among gas sellers."[300]

The Commission believes that it has made reasonable predictions about the effect of SFV on the competitiveness of the gas market. The Commission is not required to act only on the basis of hindsight. The Commission may make predictions about the markets it regulates.[301]

299. 53 FERC ¶ 61,194 at p. 61,702 (1990).

300. Petition at 9. Similarly NIEP argues that the Commission should consider the effect of post-restructuring costs on SFV.

301. Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991).

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Several petitioners[302] argue that the Commission should not mandate SFV because it will increase costs for LDCs serving residential consumers and will decrease costs for high load factor customers, primarily industrials.[303] The Commission believes that the mitigation measures of Order No. 636 and the changes made on rehearing adequately respond to any cost shift (see *infra* on mitigation). In addition, the Commission believes that the ability of consumers to acquire gas at reasonable prices in an efficient, competitive wellhead environment is far more important to the development of a national, long-term gas market. That long-term national gas market will produce benefits to balance any short-term cost shift.[304] Further, the Commission has sound ratemaking techniques available to it, such as the use of seasonal reservation quantities, which would adequately treat undue cost shifts in particular cases. Moreover, the Commission has fashioned a viable capacity release program which should further offset any consequences of a cost shift.

SoCal Gas argues that SFV will reduce competition among producers on competing pipelines because the cost to LDCs of retaining firm capacity will be greater under SFV than under MFV. It argues that MFV's lower demand charges moderate the

302. *E.g.*, Laclede, Gas Company of New Mexico, Public Service Commission of the Commonwealth of Kentucky (Kentucky PSC), CPUC, Pennsylvania PUC, and Maryland Peoples Counsel. The Pennsylvania PUC maintains that the 10 percent mitigation policy shows that SFV is *per se* unreasonable.

303. As stated above, the Commission, contrary to some petitioners (*e.g.*, the CPUC, Socal Gas, Peoples Natural Gas, and the Pennsylvania PUC) believes that SFV will benefit consumers by producing an adequate supply of gas at reasonable prices. Use of SFV is not designed to "help producer net-backs."

304. *See* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1161 (D.C. Cir 1985).

tension between retention of capacity to serve consumers and maximizing gas-on-gas competition.

SoCal Gas can continue to reserve the same amount of capacity under SFV as it did under MFV and continue to purchase gas from producers behind the pipelines on which it has firm capacity. The Commission fully expects those producers to continue to compete for SoCal Gas' business. Moreover, SoCal Gas can release unneeded capacity, if a replacement shipper can be found or if the pipeline agrees, in the restructuring proceeding as discussed above and under the Commission's capacity releasing program established by Section 284.243 of the Commission's regulations as discussed below.

The NASUCA maintains that SFV will deprive consumers of the ability to freely select among competitive services of supply and transportation by masking price differentials with respect to competing pipelines. The Commission believes that gas purchasers will be able to compute pipeline price differentials in selecting among competitive services because transportation rates will continue to be stated in pipeline tariffs. In addition, comparisons will be easier because only reservation charges need to be compared. The Commission's goal, in any event, is to eliminate as much as possible those differentials in pipeline usage charges.

Several petitioners argue that the Commission has erroneously relied solely on unproven economic theory and not on facts.[305] Similarly, both Peoples Natural Gas and Southwest Gas contend that SFV, as a system of uniform commodity charges, is the functional equivalent of an illegal "basing point" pricing system, and is, therefore, not respectable economic theory.

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305. *E.g.*, Hamilton and City Gas.

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The Commission believes that it has relied on sound economics. The development of a competitive national gas market consisting of lowest-cost, efficient producers will in the long run redound to the benefit to consumers and that the inclusion of fixed costs in pipeline firm service usage charges will inhibit that goal by distorting producer to producer competition on a nationwide basis.

The Commission does not agree that SFV may not be adopted because it resembles an illegal "basing point" pricing system where the delivered prices of a product (such as cement) are identical at any given point in order to eliminate price competition. First, the Commission is authorized to establish pipeline transportation rates to achieve the goals it determines are in the public interest. Second, SFV does not mandate a uniform delivered gas price, which is the gas price plus the transportation rate nor does it establish uniform transportation (reservation) charges. The Commission believes that the competitive national gas market will result in vigorous gas on gas competition.

C. Allocation of Costs Among Customers

Alabama Gas argues that the Commission's nationwide gas market rationale does not provide a basis for changing cost classification for allocation purposes. It refers to the Commission's recent opinion in *Panhandle Eastern Pipe Line Corp.*, where the Commission used MFV for allocation and SFV for design.[306]

The Gas Company of New Mexico asks the Commission to clarify that it has not mandated a particular basis for allocating

306. 57 FERC ¶ 61,264 (1991), *order on reh'g*, 59 FERC ¶ 61,244 (1992).

costs among customer classes or calculating the demand charge (*e.g.*, peak requirements-annual requirements or two-part demand charge).

Southwest Gas submits that on rehearing the Commission should clarify that it did not intend to prejudice the issues of the appropriateness of the use of a one part demand charge or mandate the use of peak determinants to allocate costs.

CIG asks the Commission to clarify whether demand costs are to be allocated only to peak usage or entitlement and designed into a single part reservation charge or whether it and the parties can base demand-cost allocation and the design of reservation charges on some weighing of annual entitlements to service.

The Commission's primary aim is to institute SFV on a generic basis for rate design (*i.e.*, billing purposes) in order to minimize the costs recovered in the usage charge because of the effect on purchasing decisions. Although the Commission agrees that to achieve this purpose it is not necessary for a pipeline also to use the SFV method for the allocation of costs among its customers,[307] traditionally, the Commission has used

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307. In Order No. 636 the Commission explained the five traditional steps in the ratemaking process. Order No. 636 at p. 30,431. In Order No. 636, the Commission addressed the issue of cost classification for cost allocation purposes and billing (rate design) purposes and concluded that SFV is the just and reasonable cost classification method for the assignment of costs to a reservation charge. The Commission did not directly address the fourth task of apportioning (allocating) classified costs among classes of customers or zones. This task allocates the costs, assigned under SFV to the reservation charge, by using various techniques to determine the amount of costs to be assigned to a particular zone or customer class (*e.g.*, contract demand quantities or three day peak volumes).

the same method for rate design and for the allocation of costs among customers. But, it does not have to be so.

However, the Commission clarifies that it will require the parties to use different ratemaking techniques in connection with the distribution of revenue responsibility among customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand. The pipeline would first use SFV to classify (*i.e.*, assign) all of its fixed transmission and appropriate storage costs to a one-part reservation charge for both allocation and billing purposes. If that classification causes significant cost shifts, the pipeline is required to use some measure, such as seasonal contract quantities (*i.e.*, seasonal entitlements or CDs) as a means to counteract those shifts. This would enable firm customers to lower their daily reservation quantities for the off peak season and keep the higher quantity needed for the peak season.[308] Thus, if significant cost shifts

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308. For example, assume a pipeline with an annual reservation charge revenue requirement of $10 million and two customers A and B, each with a daily reservation quantity of 166,666 Mcf per day. Thus the annual reservation quantity (billing determinants) is 4 million Mcf (2 times 12 times 166,666). The reservation charge would be $2.50 per Mcf and each would pay $5 million. However, if seasonal contract quantities were used the revenue responsibility of each would change as follows. Assume that Customer A elects an off-peak daily reservation quantity of 133,333 for a reservation quantity (billing determinants) of 800,000 Mcf (for a six month period) and an annual total of 1.8 million Mcf. Customer B elects an off-peak daily reservation quantity of 33,333 Mcf for a reservation quantity (billing determinants) of 200,000 Mcf. The result is an annual total of 1.2 million Mcf for Customer B. Thus, the combined reservation quantities (billing determinants) for the two customers would be 3.0 million Mcf and the reservation charge would be $3.33 per Mcf ($10 million divided by 3 million Mcf). Customer A would pay a total of $6 million ($3.33 times 1.8 million Mcf) and Customer B would pay $4 million ($3.33 times 1.2 million Mcf). Under either case, the pipeline will recover its

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still would occur among customers, due to the allocation of costs on peak day demand, the pipeline is required to use other appropriate techniques, such as seasonal CDs, to allocate costs. However, SFV must still be used for billing so that all fixed costs are recovered in the reservation charge.

Pipelines are required to use, in their compliance filings, SFV to allocate costs between services and zones. The Commission directs the parties in the individual proceedings to develop methods for allocating costs among services and distributing revenue responsibility among customers that will minimize significant cost shifting. The Commission strongly encourages the use of seasonal contract quantities to replicate, in part, the allocation of costs based on peak and annual considerations. The parties can explore other methods, however, a two-part reservation charge is not appropriate for allocation or billing purposes. The D-2 charge was based on usage patterns and is therefore not in harmony with the goal of SFV to minimize charges based on actual usage because usage charges can affect gas purchasing decisions. In addition, as a general matter, the Commission discourages the creation of customer classes, other than the special small customer class provided for in this rule, or if necessary during the four year mitigation period. Rather, the Commission intends for the pipelines and the paties to develop similar rates for similar services, consistent with the requirement set forth in Section 284.8(b) of the Commission's regulations.[309]

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revenue requirement. Use of seasonal CDs only changes the way that the revenue requirement is allocated between the two customers.

309. Section 284.8(b) provides that an interstate or intrastate pipeline that provides firm service under Part 284 must "provide such service without any undue discrimination or preference in the quality of service, the duration

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If at the end of this ratemaking process significant cost shifts still result, the Commission will require a four-year mitigation plan, as discussed below, to phase-in the transition. In all events, the Commission will require the use of SFV for the rate design (billing) unless ordered otherwise in accordance with 18 CFR 284.8(b).

D. Rates for Small Customers

Order No. 636 stated that "the small customers can continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined."[310] The Commission later indicated that the use of a one-part volumetric rate was a potential mitigation method for phasing-in SFV.

City Gas seeks clarification that "pipelines will be required to compute small customer rates on a one-part volumetric basis at the imputed load factor underlying the pipeline's currently effective small customer sales rate."[311] Similarly, the APGA seeks clarification that one-part, volumetric rates are not merely a temporary rate design mitigation mechanism. Atlanta Gas, however, opposes the small customer imputed load factor as an unwarranted subsidization by large customers and inconsistent with the Commission's "distorting factor" analysis.

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of service, the categories, prices or volumes of natural gas to be transported, *customer classification*, or undue discrimination or preference of any kind." (emphasis added).

310. Order No. 636 at p. 30,411 (footnote omitted).

311. Petition at 9.

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The Commission here is clarifying this small customer rate issue to preserve the status quo for this particular class of customers. In the Commission's view, this will not have an unreasonable impact on the Commission's goals in adopting SFV. The Commission is requiring all pipelines that, on May 18, 1992, offered a small customer sales or firm transportation service on a one-part volumetric basis at an imputed load factor rate to continue to offer firm and no-notice transportation services on the same basis. In addition, the Commission is requiring those pipelines to consider enlarging the size of the small customer class on their systems to include any customer with the right to transport up to 10,000 Mcf or Dth/day on a firm basis. Whether the small customer class should be enlarged up to 10,000 Mcf or Dth/day on specific pipelines will be resolved by the Commission in the specific restructuring proceedings. The purpose for enlarging the small customer class would be to mitigate the effect, of shifting to the SFV method, on small customers who do not currently qualify for a pipeline's small customer rate schedule. However, the Commission is also requiring eligible small customers that elect to retain or receive small customer service not to ship gas under any interruptible transportation service available from the pipeline or not to ship gas as a replacement shipper under the capacity releasing mechanism of Section 284.243 unless the customer has exhausted its daily levels of firm service entitlement for that day. Other eligibility criteria would be based on the pipeline's existing tariff. The Commission is imposing this narrow limitation because the small customers are required to pay only when they use the pipeline. This serves the same functional purpose as sole supplier provisions did in the same customers' contracts to the extent they had those provisions.

In their compliance filings, the pipelines must file rates for the small customer service determined by using a load factor

no less than the current imputed load factor. If the pipeline or another party, such as Atlanta Gas, wants to lower the existing imputed load factor or eliminate the use of a one-part rate, it must seek to do so in a new rate proceeding and not in the restructuring proceeding.

E. Costs Shifts to Firm Customers

The Coalition argues that SFV will cause a massive industry-wide shifting of costs from interruptible transportation customers to firm customers. The Coalition claims that a change from Seaboard to SFV will shift $5.9 billion to the demand charge and a change from MFV to SFV will shift $4.3 billion to the demand charge. The Coalition further maintains that approximately 60 percent of total throughput is interruptible industrial transportation, although they do not cite a source for this number.[312] It asserts that this results in shifts of about $3 billion (60% x $5 billion) per year or $60 per year per customer.[313]

The Coalition's study does not present an accurate portrait of the changes effected by Order No. 636. The Commission expects the overall effect of Order No. 636 will benefit generally industry participants by furthering the creation of an efficient national wellhead market. Hence, focusing on cost shifts is to focus on but one aspect of Order No. 636. Moreover, cost shifting

312. The Coalition's information may have come from the Energy Information Administration's (EIA) Natural Gas Monthly publication which shows gas consumption by Electric Utilities and Industrial Customers in 1990 of about 58 percent. Energy Information Administration/Natural Gas Monthly (May 1992); DOE/EIA - 0310 (92/05), from: Table 3. Natural Gas Consumption in the United States, 1986-1992.

313. The Coalition has assumed 50 million gas customers.

is not a generic matter; the key question is how costs are redistributed among customers on a particular pipeline. In addition, the Commission has provided measures to deal with cost shifts (see *infra* on cost allocation and rate design).

Despite its neglect of the benefits from Order No. 636, the Coalition attempts to quantify the possible shift in costs from interruptible customers to firm customers brought about by the shift to SFV rate design. However, the Coalition is mistaken both as to how costs are recovered from interruptible shippers now and how they will be recovered under SFV rates. Moreover, all the numbers the Coalition uses to support its estimate are inappropriate. The Coalition appears to believe that interruptible shippers pay only a portion of the fixed costs that are assigned to the commodity charge, whereas in fact 100 percent load factor interruptible transportation rates are designed to recover some fixed costs in the demand charge. Under SFV, the Coalition appears to believe that interruptible transportation shippers will not pay any portion of the pipeline's fixed costs, whereas in fact neither this order nor Order No. 636 necessarily requires any change to the methods used for setting interruptible rates.

Using certain assumptions the Commission can generally estimate the amount of costs that could shift. Under MFV, costs are split into three categories. First, the pipeline's return on equity and associated taxes go into the usage category. In 1990, these amounted to $1.7 billion,[314] rather than the $4.3 billion

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314. Energy Information Administration/Statistics of Natural Gas Pipeline Companies 1990; DOE/EIA - 0145(90), from: Table 3. Composite Statement of Income and Retained Earnings, Major Pipeline Companies, 1981-1990. Table 3 shows gas operating revenues of $1.685 billion. From this we deduct interest expense of $.594 billion (assuming the company wide ratio of 35.23 per cent of interest expense to net income holds for the transmission

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estimated by the Coalition.[315] These costs are recovered from each unit of throughput. In 1990, total throughput for the interstate pipeline system was about 19.9 Tcf.[316] Total throughput was almost evenly divided between firm customers (9.9 Tcf) and interruptible shippers (10 Tcf).[317] Thus, interruptible shippers paid about 50 percent of fixed usage costs ($.85 billion). The remaining fixed costs of the pipeline, about $7.8 billion,[318]

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function alone) to get a return (after taxes) on equity of $1.09 billion. The federal and state composite tax rate is about 36 per cent, so a pre-tax income of $1.70 billion is necessary to yield an after tax income of $1.09 billion.

315. The Coalition's figure is overstated because the net income reported in Statistics of Natural Gas Pipeline Companies, EIA- 0145(90), Table 3, includes income relating to the pipelines total business, utility and non-utility, and not just to transmission expenses as it should. The tax figure is overstated for similar reasons and does not reflect the income tax allowance as included in rates.

316. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1990 (July 1991), from: Table A-1, which shows carriage for market plus sales of 17.109 Quads. The pipelines in INGAA's survey account for 86 per cent of gas deliveries; the figure in the text was derived by multiplying 17 x 1/.86 and rounding.

317. *Id.* Table A-7, Sales and Firm and Interruptible Transportation as a Percentage of Total Delivered for Market, shows 51 percent as the share of interruptible transportation.

318. This was estimated by subtracting total purchased gas costs of $12 billion, Statistics of Natural Gas Pipeline Companies 1990, Table 9, from the revenue from sales of $16 billion *Id.*, recovered from sales customers. Add to this, revenues from transporting gas of others of $5.5 billion, to get the $9.5 billion in the text. The Commission recognizes that there are upstream capacity costs representing inter pipeline sales (Account No. 858 costs) included in the $12 billion.

were split fifty-fifty between D1 costs ($3.9 billion), which are recovered on the basis of contract demand (CD) with an imputed CD for interruptible customers, and D2 costs ($3.9 billion), which are recovered on the basis of nominated annual throughput for firm customers and projected annual throughput for interruptible shippers. Total contract demand for all interstate customers in 1990 was about 75 Bcf per day or 27.5 Tcf per year.[319] If projected interruptible transportation throughput was assumed equal to the actual of 10 Tcf, then the $3.9 billion per year of D1 costs would have been recovered from each of the 37.5 Tcf reserved per year (27.5 in CD plus 10 Tcf in interruptible transportation imputed CD).[320] Interruptible transportation shippers thus paid 27 percent (10/37.5) of the D1 costs or about $1 billion. Similarly, if one assumes that firm annual D2 nominations are equal to actual firm annual throughput, then the D2 costs of $3.9 billion were recovered from each of 20 Tcf units shipped, and interruptible transportation shippers paid about 50 percent of $1.95 billion.

Thus, the Commission estimates that under MFV, interruptible transportation shippers paid about 40 per cent of the total fixed costs, or about $3.8 billion. Shifting to SFV would have put all costs in the D1 category. If there were no change in the interruptible transportation projected throughput, interruptible transportation customers would have been allocated 27 percent of the total, or about $2.5 billion. There would have been a shift of costs from interruptible transportation shippers to firm customers of about $1.3 billion, rather than $3 billion estimated by the Coalition.

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319. Capacity and Service on the Interstate Natural Gas Pipeline System 1990, EIA-0556, June 1992, Table ES1, p. xi.

320. This results in a D1 charge of 10.4 cents per mcf reserved per day, or $3.12 per month.

But even this number is too large. Many firm sales customers have been buying gas from non-pipeline sellers and shipping it on an interruptible basis. In 1990, at least 27 percent of the 10 Tcf of interruptible transportation throughput was for LDCs.[321] Thus, non-LDC interruptible transportation shippers paid about $2.8 billion in 1990, not $3.8 billion.[322] If the D1 billing determinants are adjusted to take into account a decrease in interruptible transportation done by LDCs, interruptible transportation would be projected to be 7.3 Tcf, rather than 10 Tcf. Non-LDC interruptible transportation shippers would pay about 21 percent (7.3/(7.3 + 27.5)) of the costs, or about $2 billion. This means the shift from non-LDC interruptible transportation customers to firm customers is about $.8 billion ($2.8 - $2).[323]

If $.8 billion[324] was shifted to firm customers from

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321. INGAA's Carriage Through 1990, Table B-3, *supra*, shows that LDCs accounted for 27 percent [17/64] of the total IT throughput, while marketers accounted for 61 percent [39/64]. It is likely that marketers resold some of this gas to LDCs, so the 27 percent figure is probably an underestimate.

322. This is derived by multiplying 73 percent (non-LDC interruptible shippers throughput) times $3.8 billion, $2.8 billion.

323. This is derived by multiplying 21 percent (non LDC interruptible transportation share of D1 costs times $9.5 billion, $2 billion, and subtracting $2 billion from $2.8 billion.

324. Even this number is too large, because D2 costs are far less than the amount assumed since many pipelines have already eliminated them. In addition, some major pipelines are already operating on EFV which puts only half the MFV amount in commodity and none in D2. Moreover, some pipelines already have SFV in effect and the calculation does not take into account any revenue from firm capacity holders releasing capacity.

interruptible shippers, how much more would the 50 million residential gas customers pay? Residentials consumed 26 percent of the total gas delivered to consumers in 1990.[325] If they paid a proportionate share of the shift, their annual bill would increase by $.21 billion, or about $4.20 per year or 35 cents per month. If they paid *all* of the shift (that is, commercial, industrial and electric utility customers of LDCs paid *none* of the shift), then their annual bill would increase by $16.20 or by $1.35 per month. Since LDCs billed residential gas customers over $25 billion in 1990,[326] or over $500 per customer per year, even this most extreme shift would amount to about a three percent increase in annual bills. While the Commission believes its estimate is reasonable and more accurate than the Coalition's, the Commission recognizes that it is not a precise estimate of potential cost shifts.

F. Mitigation of Cost Shifts

In Order No. 636, the Commission recognized that the change from the use of MFV can result in the shifting of revenue responsibility among classes of customers. The Commission concluded that it was appropriate to require pipelines to mitigate a shift in revenue responsibility if it results in a 10 percent or greater increase in revenue responsibility for any historic customer class. The Commission is requiring each pipeline to develop and implement a plan to phase-in any such rate increase over no more than four years.

Several petitioners make a variety of arguments about why the mitigation measures are not adequate. They argue that the

325. Natural Gas Monthly, *supra*, Table 3.

326. Gas Facts, 1990 Data, American Gas Association, Table 7-1.

Commission has provided no rationale to support the ten percent or greater bright line test, that mitigation should be by customer rather than by customer class, and that permanent measures are necessary to avoid unjust and unreasonable rates.[327] Some petitioners argue that mitigation should be a restructuring issue without a threshold or phase-in period.[328]

The Industrial Groups maintain that the combination of SFV with mitigation through cost allocation methods will result in different rates for the same service which is discriminatory and, if based on historical usage patterns, unlawful retroactive ratemaking. It adds that there is little basis to assume that historical load factors will remain the same in light of the institution of capacity releasing, flexible delivery points, and open access storage.[329] They suggest phasing-in SFV at the cost classification stage based on current load factors so that all customers are treated equally.

Northern Illinois Gas supports mitigation but not simply to shift costs to other firm customers, "who are already paying all fixed costs properly related to their capacity entitlements."[330]

Several petitioners ask for clarifications. Northwest Pipeline

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327. *E.g.*, Hamilton, Gas Company of New Mexico, Kentucky PSC, Citizen Action, Kansas Corporation Commission (KCC), NASUCA, Tennessee and Columbia Small Customers, Alabama Gas, and Cascade.

328. *E.g.*, Hamilton, Alabama Gas.

329. The Industrial Groups also note that mitigative rates will result in different capacity releasing prices.

330. Petition at 23.

asks the Commission to clarify "how the historical customer class will be defined — by pipeline historic rate schedules, by current pipeline rate schedules, by total yearly throughput, by load factor profile, by individual customer or other criteria."[331]

The KCC is concerned about strict application of use of a pipeline's last approved cost classification and rate design method in performing the mitigation analysis. It cites, for example, Williams Natural Gas Company's one-part commodity firm sales rate.

City Gas asks for clarification about what costs and in what manner the Commission will compare them to determine whether a customer class that no longer exists after Order No. 636 has received increased revenue responsibility. It asks whether the Commission will compare SFV rates with MFV rates based on the currently effective cost of service and service portfolio, or based on projected, post-Order No. 636 cost of service and service portfolio.

The Commission upholds the mitigation approach set forth in Order No. 636. The Commission believes a fixed mitigation trigger for the industry is appropriate rather than a case-by-case approach, because SFV is being adopted on a generic basis. Based on the Commission's judgment, 10 percent is appropriate for the bright-line test. However, with the changes made in this order, the Commission expects there to be a diminished need to phase-in the changes required by the rule. Small customers are retaining their right to a one-part volumetric rate at an imputed load factor and pipelines will use an apportionment method , such as seasonal reservation quantities, to appropriately allocate costs among individual customers. These changes should minimize the need to use the phase-in mitigation measures.

331. Petition at 10,11.

If needed, however, the Commission continues to believe that the need for mandatory mitigation should be determined by a measure of shifts between historic customer class rather than by individual customer, because rates historically have been set by customer class and not for individual customers.

The Commission believes further that the four-year mitigation plan should be transitional rather than permanent because SFV is a just and reasonable cost classification method. Mitigation is adopted as an equitable matter solely to allow the orderly transition to SFV.

While it is true that four-year mitigation, if needed, may result in varying rates for the same service depending upon the mitigation measure adopted, this discrimination is not undue for this transition period because mitigation is appropriate to soften the impact of the adoption of SFV. Mitigation is not retroactive ratemaking. The pipelines will not be recovering past losses in present rates. Rather, the mitigation formula is similar to any phasing-in or phasing-out of a subsidy.

It is possible, as maintained by the Industrial Groups, that a customer's load factor will change in light of the policies instituted by Order No. 636. But the Commission is mitigating by historic classes of customers to alleviate rate shock among those different classes of customers. Individual changes in load factor are not pertinent to mitigation by classes of customers.

The Commission clarifies that historic customer class refers to classes existing prior to May 18, 1992. For example, if a pipeline has a firm sales customer class existing prior to May 18, 1992, and that class will have an 11 percent increase, the pipeline must mitigate the impact of the change to SFV for all

members of that class. A pipeline must use its throughput and cost-of-service underlying the currently effective rates (even if they are subject to refund) to make this mitigation calculation.

G. Other Rate Designs

In Order No. 636, the Commission stated that it will consider alternative rate design proposals when the parties agree to a rate design other than SFV, but stated that those parties supporting a rate design other than SFV bore a heavy burden of persuasion.

New Jersey Natural, Pennsylvania PUC, and National Association of Regulatory Utility Commission (NARUC) object to the "heavy burden" standard. For example, NAURC argues that it is concerned it will become an irrebuttable presumption in favor of SFV. It asks the Commission to provide greater detail about what needs to be shown to meet the heavy burden of persuasion. In addition, the Wisconsin Distributor Group and NARUC maintain that the Commission should clarify that it will accept rather than consider other rate designs. The former contends that the Commission should grant effect to substantially uncontested agreements among interested parties. The Iowa, Missouri, and Wisconsin Commission suggest the following approach:

> If all of the rate case participants wish to implement something other than pure SFV, the Commission should accept the choice. If a substantial majority of rate case participants agree on a rate design which does not implement pure SFV, the Commission should place the burden on the objecting parties to

justify why the majority agreement should not be accepted by the Commission.[332]

Columbia Gas Distribution Companies maintain that the Commission has precluded itself from adopting MFV, in giving effect to the parties' agreement to MFV, by its finding that MFV, is unjust and unreasonable, a possible "per se" NGA Section 5 violation. They suggest amending Order No. 636 to clarify, "in terms stronger than 'unless the Commission permits otherwise' . . . that the Commission retains the ability to approve non-SFV rate designs, including MFV."[333]

The Commission denies rehearing and adheres to its Order No. 636 discussion that it will carefully consider arguments for and against deviations from SFV, with the advocates against SFV bearing the burden of persuasion. This is not an irrebuttable presumption. At a minimum, opponents of SFV must demonstrate that SFV is not needed to effectuate the goals of Order No. 636. The Commission's finding that MFV is unjust and unreasonable is not a "per se" finding with respect to future individual pipeline rate proceedings, but a generic finding that the impact of MFV for billing purposes is unjust and unreasonable on a generic basis under the present circumstances.[334]

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332. Petition at 16-17.

333. Petition at 5.

334. See Freeport Interstate Pipeline Co., 59 FERC ¶ 61,378 (1992) for an example of the retention of MFV based on individual circumstances.

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H. Other Matters

1. Alternative Fuels

Southwest Gas argues that there is no record support for the Commission's conclusion that SFV is needed to make gas more competitive *vis-a-vis* other fuels and to encourage the use of gas (as opposed to foreign oil). It maintains that the delivered price of natural gas is already well below that of heavy oil and well above that of coal.[335] Alabama Gas adds that the Commission has ignored the pipelines' ability to discount rates.

The Commission's conclusion was not that SFV is needed now to make gas more competitive with other fuels, but that SFV will enable gas to compete more readily, on a timely basis, by allowing the price of gas to adjust without regard to transportation fixed costs.

2. Impact on Gas Prices

NYSE&G maintains that the Commission needs to perform an elasticity analysis of the impact of changes in prices for pipeline transportation service on the demand for supplies behind competing pipelines. The Commission is not required to perform impact studies in connection with SFV's impact on the demand and price of gas suppliers.[336] The Commission believes that the effect of SFV on national wellhead competition will be to produce an adequate supply of gas at reasonable prices.

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335. See also Northern Illinois Gas, Atlanta Gas, Peoples Natural Gas, and Alabama Gas.

336. Cf. Wisconsin Gas Co., v. FERC, 770 F.2d 1144, 1155 (D.C. Cir. 1985).

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3. Other Rate Design Goals

Several petitioners argue that the Commission in adopting SFV has ignored past precedents and goals with respect to the designing of rates.

Washington Gas contends that there is no evidence to support the finding that the MFV rate design fails to promote the efficiency goals under Commission regulations or the Rate Design Policy Statement, or that a mandated SFV will improve economic efficiency. It maintains that there is no evidence that the higher demand charge of SFV would better ration firm capacity generally or a connection between MFV and under utilized capacity.

Arizona Electric argues that SFV encourages usage at peak when rationing is needed and, therefore, does not promote efficient utilization, and ignores the market-clearing role of usage charges.

Washington Gas also argues that the Commission should reverse its mandate of SFV and allow particular rate designs to be developed in individual pipeline rate proceedings under the guidance of the Rate Design Policy Statement.

The Commission did not apply the policies enunciated in the Rate Design Policy Statement because in its current assessment of the prevalent economic and market circumstances it believes the goal of achieving an efficient, national gas market is the factor that should control the selection of the appropriate rate design method. This does not mean that rationing capacity and maximizing throughput are not legitimate rate design functions. For example, it may be appropriate to apply the Rate

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Design Policy Statement in determining whether seasonal rates are appropriate.

The Coalition, Southern Indiana, and the State of Michigan maintain that the Commission ignored precedent by failing to take into account the fact that a pipeline incurs fixed costs to serve all throughput.[337] The Coalition maintains that several costs are the responsibility of total throughput under the "cost responsibility" principle.[338]

The Commission recognizes that a pipeline has throughput throughout the year. The proper allocation of fixed costs between peak and off peak customers presents a difficult issue which regulators have grappled with for many years. This, like all other ratemaking matters, is not an exact science and the Commission must use its judgement and expertise to select ratemaking practices that benefit all gas consumers.

As a result, the Commission believes that the goals to be accomplished via SFV outweigh generally the goal of allocating fixed costs to annual throughput. There are many functions that can be performed by rate design. The allocation of fixed costs to annual throughput is but one of them. The Commission is not bound to adopt a cost classification that performs that function when another function is more appropriate in the prevalent circumstances. However, as discussed above, the Commission is requiring adjustments in connection with the distribution for revenue responsiblity among customers to avoid significant cost shifts among pipeline customers.

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337. *See, e.g.*, Atlantic Seaboard Corp., 11 FPC 43 (1952) and Texas Eastern Transmission Corp., 30 FERC ¶ 61,144 (1985).

338. *See, e.g.*, Atlantic Seaboard Corp., 11 FPC 43 (1952) and Texas Eastern Transmission Corp., 30 FERC ¶ 61,144 (1985).

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Several petitioners argue that under SFV pipelines will have no incentive to operate their systems on an efficient basis to control costs and to maximize throughput.[339] Brooklyn Union argues that the "Commission must require pipelines to implement appropriate incentive rate mechanisms at the same time that SFV rates are implemented."[340] Brooklyn Union argues that this is necessary to replace the loss of the tool against excessive pipeline charges of not fully recovering fixed costs unless pipelines minimize costs and operate efficiently. However, other petitioners argue that the Commission should defer the adoption of SFV and consider SFV and incentive ratemaking together in a separate proceeding.[341] United Distribution Companies maintains that incentive ratemaking should not be part of the restructuring process to eliminate a pipeline bargaining chip. It asks the Commission to reject incentive rate filings that do not give the pipeline a stake in throughput. The Commission will address incentive ratemaking matters below. Here, it suffices to state that the Commission will not require incentive ratemaking to be implemented at the same time as SFV in the compliance filings to Order No. 636.

4. Alternative Solutions

Arizona Electric Cooperative argues that "geographic equalization" (*i.e.* producers in different areas) could be achieved

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339. *e.g.*, Northern Illinois Gas, the Industrial Groups, SoCal Gas, Southern Indiana Gas and Electric, the Gas Company of New Mexico, Laclede Gas, Kentucky PSC, the Illinois Commerce Commission, Citizen Action, CPUC, NASUCA, Citizens Gas, and APGA.

340. Petition at 15.

341. ConEd, NYSE&G, Peoples Natural Gas, Alabama Gas, New England Gas Distributors, NIEP, and AGD.

by discounting or by volumetric transportation rates based on marginal costs. Its maintains that those rates will create demand-responsive volumetric charges which will rise during peak usage periods. It adds that reservation fees would then be set at a much lower level because they would only have to recover any revenue shortfall expected to result from the volumetric charges.

Peoples Natural Gas asserts that the Commission should adopt SFV rates as utilized in the electric industry, where the demand charges apply to customer's actual peak consumption during the given months.

Peoples Natural Gas argues that the Commission could have remedied the distortion by adopting a uniform volumetric rate (including fixed costs) on all pipelines without harming consumers by shifting all costs to them from producers as it claims is done by SFV.

The Industrial Groups agree that MFV is unlawful, but would prefer Enhanced Fixed Variable, which includes 50 percent of a pipeline's equity return and related taxes in its usage charge.

The Commission believes that SFV, as adopted by in Order No. 636, is the best rate design vehicle for achieving the Commission's goals. This is because SFV, unlike the other proposals, best eliminates the distorting impact of pipeline fixed costs on wellhead competition. The other proposals, by recovering fixed costs through usage factors, would not do that.

5. Unallocated Capacity

Several petitioners argue that the pipelines should bear

the costs associated with unbooked firm capacity.[342]

Order No. 636 did not address the issue of the appropriate aggregate firm volumes to use in designing the firm transportation reservation charges. This is, therefore, not an Order No. 636 restructuring issue but rather, is an issue for a rate proceeding.

6. New Entrants

SoCal Gas argues that SFV will, like minimum bills, make it substantially more difficult for new pipelines to compete with existing pipelines to provide firm transportation services in existing markets. The Commission believes that new capacity should be built to meet demand for capacity. If demand exists, SFV should not be a deterrent to new construction.

7. Demand Charge Credits

ConEd, AGD, and Peoples Natural Gas argue that pipelines should be required to provide demand charge credits during service interruption or curtailment to provide an incentive to expeditiously restore service.[343] Because this issue does not pertain to Order No. 636, it should be resolved in individual rate proceedings and not in this order or the restructuring proceedings.

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342. Northern Illinois Gas, Illinois Power, Northern Indiana, and City Gas (suggests assigning these costs to commodity charge). United Distribution Companies suggests designing at 110% throughput to introduce the element of competitive risk.

343. *See* Northern Natural Gas Co., 57 FERC ¶ 61,105 at p. 61,400 (1991).

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8. Rate of Return/Risk

In Order No. 636, the Commission stated that "pipeline risk is a matter for pipeline-specific analysis in light of all risks."[344]

Several petitioners asks the Commission to reduce the pipelines' rate of return on equity and to reflect the decline in pipeline risk under SFV.[345] The Arizona Direct Customers asks the Commission to clarify "that all other things being equal, a pipeline's move from the MFV to SFV method of cost classification and rate design reduces a pipeline's risk of inadequate revenue recovery, and this reduction in risk is a relevant factor in arriving at an appropriate return on equity."[346] The New England Distributors maintain that the Commission should act in individual NGA section 4 proceedings in order to consider reduced pipeline risks.

The pipelines argue that their risk will increase after restructuring. For example, INGAA submits that "if the Commission considers all risk confronting pipelines after restructuring, it will allow pipelines higher rates of return on equity."[347] INGAA refers to risk related to the "difference between the rate negotiated and the maximum rate" and risk associated with interruptible service because the pipeline may not sell its own capacity first. ANR asks the Commission to clarify that the implementation of the SFV rate design does not

344. Order No. 636 at p. 30,437.

345. Pennsylvania PUC, Citizen Action, CPUC, the Industrial Groups.

346. Petition 10.

347. Petition 7. See also Natural's Petition at 19.

itself require a lowering of the return on equity component of a pipeline's rates.

The Commission adheres to Order No. 636's conclusion that "pipeline risk is a matter for pipeline-specific analysis in light of all risks."[348] As such, this is not a restructuring issue but rather is an issue that may be raised in individual pipeline rate proceedings where the Commission examines a pipeline's cost-of-service, including the return on equity.

9. Prospective Basis

The APGA asks for clarification that pipelines may implement SFV increases on a prospective basis only and not retroactively to the effective date of any currently active section 4 proceeding. The Commission so clarifies, unless the pipeline proposed SFV in such a proceeding, then a mitigation measure may be required back to the date the rates became effective in connection with the implementation of SFV.

10. By-Pass

The State of Michigan argues that SFV will create incentives for by-pass. The Commission will discuss by-pass issues below in Part IX, B, 13. Here, it suffices to state that SFV's impact on by-pass is a speculative matter dependent on the method for the flow though of fixed costs used by a state commission.

11. Section 7(c) Transportation

National Fuel asks the Commission to require pipelines to adopt SFV for individual NGA section 7(c) transportation

348. Order No. 636 at p. 30,437.

services because the Commission's rationale applies with equal force to those services. The Commission agrees that the rationale for SFV applies to all firm transportation. As the Commission has required in the past, the same rates must be charged for individually authorized NGA section 7(c) transportation and for Part 284 transportation and will permit individual NGA section 7(c) transportation rates to be so designed. If a party opposes that design for those services, it may raise its objection in the pertinent restructuring proceeding.

12. Vintage Pricing

Great Lakes Gas Transmission Limited Partnership (Great Lakes) requests clarification that equal transportation on even terms requires the elimination of vintage pricing in favor of a uniform, market-based rate for comparable transportation services (constrained by the pipeline's highest cost-based tariff rate applicable to such services). The Commission will address this issue in Great Lakes' own proceedings concerned with vintage pricing rather than here or in the restructuring proceeding.

13. Rate Design Policy Statement Policies

In Order No. 636, the Commission stated that the policies enunciated in the Rate Design Policy Statement continue in effect except for the classification of costs to the reservation and usage charges. The Commission specifically referred to, as examples, the determination of rates for interruptible transportation, the discounting of rates, and mileage-based rates.

The Arizona Direct Customers seeks clarification that "pipelines must unbundle gathering costs from the mainline rates

and that all other principles set forth in the Policy Statement and not explicitly modified by the Final Rule Remain in effect."[349] The Commission reiterates that the policies enunciated in the Rate Design Policy Statement continue in effect except for the classification of costs to the reservation and usage charges for billing purposes For example, as discussed above, pipelines can allocate or apportion costs under other ratemaking techniques, such as seasonal contract entitlements. In contrast, under seasonal rates, peak period reservation charges would be higher than off-peak reservation charges. Cost unbundling is discussed below.

14. Unbundling of Costs

NGSA seeks clarification with respect to Order No. 636's alleged vagueness concerning cost unbundling. NGSA asks the Commission to endorse cost unbundling by expressly amending Sections 284.7(d)(i) and (ii) to insert "unbundled" before service, and by including Section 284.7 among the listed regulations subject to implementation in the order No. 636 compliance filing.[350] NGSA also asks the Commission to direct pipelines to unbundle their costs into the smallest service components practicable. NGSA states that without the fullest practicable level of cost unbundling, parties may not be able to detect cross-subsidies and the potential for improper pricing will remain.

The Commission believes that it need not amend its

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349. Petition at 9.

350. Petition at 16. It appears that NGSA means Section 284.7(d)(4)(i) and (ii). For example, the former section as proposed to be amended would read: "Any maximum rate filed under this section must be designed to recover on a unit basis, solely these costs which are properly allocated to the unbundled service to which the rate applies."

regulations as suggested by NGSA because sections 284.7(d)(4)(i) and (ii) require rates to be based on the costs which are properly allocated to the service to which the rate applies. This covers all Part 284 services offered by the pipeline. Those services are unbundled from sales. Further, in Order No. 636, the Commission required the pipelines to identify the costs associated with the discrete elements of "no-notice" transportation service, such as the cost of any system storage or imbalance services.[351] The Commission believes that these existing requirements are adequate to satisfy NGSA's request and no further requirements are necessary at this time.

Northwest asks the Commission to clarify that customers should only be required to pay for the particular unbundled services (*e.g.*, gathering, transportation, and storage) that the customers use, and that customers should not subsidize services that they are not using. Similarly, Phillips maintains "that a pipeline may not use a cost allocation or rate design methodology for upstream facilities to gain price advantages for the pipeline's merchant function or to gain competitive advantages for pipeline-owned upstream services over third party providers of upstream services."[352]

As stated above, the Rate Design Policy Statement remains applicable to issues other than the apportioning of fixed costs to the reservation and usage charges. Order No. 636 dealt only with that issue and not with issues such as whether gathering and other production area services, such as processing and production area transportation, should be offered as separate

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351. Order No. 636 at p. 30,422.

352. Petition at 7. See also Natural Gas Clearinghouse, CPUC, and Arizona Direct Customers.

services with separately charged rates.[353] That is still a matter for individual pipeline rate proceedings. However, the Commission repeats its strong preference for fully unbundled services.[354]

I. Interruptible Rate Design

The Industrial Groups[355] contend that the Commission erred in leaving the issue of interruptible rate design (particularly the 100% load factor design) to proceedings under the Commission's Rate Design Policy Statement.[356] They argue that fixed costs should not be attributed to interruptible transportation because such costs are incurred to meet firm, not interruptible requirements. They further contend that maintaining historically high maximum interruptible service is unjustified since the quality of interruptible rates will decline due to the increased use of firm transportation under capacity release and mid-month bumping of interruptible transportation by firm transportation. The KCC, on the other hand, requests that fixed costs should still be allocated to interruptible customers when interruptible volumes flow during peak periods on pipelines with excess capacity.[357]

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353. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 at p. 62,059 (1989), *order on reh'g*, 48 FERC ¶ 61,122 (1989).

354. *Id.* and Panhandle Eastern Pipeline Co., 59 FERC ¶ 61,264 (1991), *order on reh'g*, 59 FERC ¶ 61,244 (1992).

355. Petition at 25-28.

356. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 (1989), *on rehearing*, 48 FERC ¶ 61,122 (1989).

357. Petition at 2.

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The Commission grants rehearing and directs that issues involving the appropriate rate design for, and allocation of costs to, interruptible transportation must be addressed in the restructuring proceedings.

VII. PIPELINE SALES

Order No. 636 issues blanket certificates to open access pipelines authorizing firm and interruptible sales for resale. The pipeline will be able to sell gas at market-based rates because Order No. 636 concludes that pipelines have no significant market power as sellers of gas on a unbundled basis. In addition, pipeline unbundled sales service will be afforded pregranted abandonment, and pipelines will be subject to standards of conduct and reporting requirements similar to those imposed in Order No. 497.

On rehearing, the Commission is modifying Order No. 636 to require pipelines to continue to sell gas to their current small sales customers (only) at a rate that is cost-based, for a transitional one-year period.

A. Blanket Sales Certificate

Order No. 636 issues to pipelines providing open access transportation, a blanket certificate authorizing unbundled firm and interruptible sales. Under the Rule, existing bundled firm sales entitlements of the pipeline's customers will be converted to an equivalent amount of unbundled firm sales service and firm transportation rights. During the restructuring proceedings, a firm sales customer can elect whether to continue its contractual relationship with the pipeline under the blanket certificate. Under the new blanket sales certificate, the pipeline's sales obligation will be coextensive with its contractual

obligations and unbundled sales will be afforded pregranted abandonment.

APGA and Citizen Action argue that the Commission erred in eliminating individual sales certificates, agreements, and accompanying rights, including abandonment protection and replacing them with a blanket certificate. The parties assert that unbundled sales under the blanket certificate are inferior to current bundled sales and that the Commission has failed to meet its burden of showing that this is required by the public convenience and necessity as required by section 7 of the NGA. As the Commission explained in sections III and IV above, unbundling is required because bundled sales service violates sections 4 and 5 of the NGA, and the Commission's action here is consistent with those sections of the NGA. The requirements of Order No. 636, including unbundling and pregranted abandonment, are all necessary to assure that Part 284 transportation is performed on a just and reasonable basis with respect to all gas supplies. As further explained above, the Commission's action under section 5 is not a revocation of the certificate. The pipeline's certificate obligations with respect to individual services are subsumed into the new blanket certificate with just and reasonable terms consistent with the Commission's findings here.

OkTex Pipeline Company (OkTex) argues that the Commission cannot require a pipeline to accept a certificate of public convenience and necessity[358] and cannot require a pipeline to perform a service it does not seek to perform or that is outside the scope of its business undertaking. OkTex asks the Commission to clarify on rehearing that it will not be required to accept a blanket sales certificate, and will not be subject to

358. OkTex cites, *inter alia*, Associated Gas Distributors v. FERC, 824 F.2d 981, 1041 (D.C. Cir. 1987).

the standards of conduct or reporting requirements simply because it could have accepted a certificate or may elect to do so in the future.

The Commission grants the clarification. Order No. 636 does not require a transportation-only pipeline to engage in sales. Because the standards of conduct in section 284.286 address the relationship between a pipeline's transportation service and its merchant function, they are not relevant to a pipeline that does not engage in sales.[359]

United asks the Commission to clarify that a pipeline will only be required to offer an unbundled sales service to its current sale-for-resale customers up to the currently certificated sales levels applicable to each customer at the delivery points where such service is currently provided. United argues that to go beyond this would be contrary to section 7 of the NGA by imposing certificate obligations which have not been requested by the pipeline and by compelling a service the pipeline is not able to perform.

The Commission clarifies that during restructuring the pipeline's current firm sales customers can elect whether to continue their contractual relationship for gas sales with the pipeline under the blanket sales certificate. The pipeline must continue to provide sales service to its current customers who elect to continue their contractual relationship for gas sales with the pipeline, until the contract expires. This service will be authorized under the pipeline's blanket sales certificate. As such, sales will be unbundled and made at a point upstream and not at the currently certificated delivery points for sales. The obligation

359. If, however, a pipeline chooses to engage in sales in the future, it must file appropriate tariff sheets and comply with the standards of conduct and reporting requirements.

to transport gas will go to the existing delivery points, but in accordance with the rules governing flexible delivery points, the pipeline cannot require deliveries only to existing delivery points.

B. Pricing

Order No. 636 permits pipelines offering unbundled sales to adopt a market-based pricing mechanism for their unbundled sales service upon full compliance with the rule. The Commission found market-based pricing would be justified because sales by non-pipeline merchants would be sufficiently competitive with sales by a restructured pipeline to prevent such a pipeline from exercising market power. Requests for rehearing of this portion of the rule were filed by APGA, Gas Company of New Mexico, Northern Distributor Group, Columbia, Tenneco, Citizen Action, National Association of Gas Consumers, the State of Michigan, Marathon, and Industrial Groups.

1. Statutory Authority

APGA, Gas Company of New Mexico, Northern Distributor Group, Citizen Action, National Association of Gas Consumers, and Marathon allege that the light-handed regulatory approach adopted in Order No. 636 goes too far and constitutes unauthorized deregulation of pipeline sales. These parties point out that the primary purpose of the NGA is to protect consumers from exploitation by natural gas companies[360] and to assure consumers an adequate supply of gas at a reasonable price.[361]

360. APGA and Gas Company of New Mexico cite FPC v. Tennessee Gas Transmission Co., 371 U.S. 145, 154 (1962).

361. APGA and Gas Company of New Mexico cite Tejas Power Corp.

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While conditions in the natural gas market may have changed, they argue that these statutory responsibilities have not. These parties argue that neither the NGPA nor the Wellhead Decontrol Act deregulates sales for resale and that the Commission cannot lawfully execute its responsibilities in a manner that is tantamount to deregulation.[362]

The Commission has considerable flexibility in selecting the methodology it will use to determine just and reasonable rates.[363] No single rate method need be followed and the Commission does not have to adhere rigidly to a cost-based determination of rates.[364] As the Court stated in *FPC v. Hope Natural Gas Co.*, "[u]nder the statutory standard of just and reasonable, it is the result reached, not the method employed, that is controlling."[365]

The courts have recognized that an agency may move from

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v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

362. APGA cites Maislin Industries, U.S. Inc. v. Primary Steel, Inc., 497 U.S. 116 (1990); Mid-Louisiana Gas Co. v. FERC, 664 F.2d 530, 535 (5th Cir. 1981), *vacated and remanded on other grounds*, Public Service Comm'n of New York v. Mid-Louisiana Gas Co., 463 U.S. 319 (1983); Public Service Comm'n of New York v. FPC, 511 F.2d 338, 354 (D.C. Cir. 1975); and Texaco, Inc. v. FPC, 474 F.2d 416, 423 (D.C. Cir. 1972), *vacated and remanded on other grounds*, 417 U.S. 380 (1974).

363. *E.g.*, FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

364. *E.g.*, Wisconsin v. FPC, 373 U.S. 294, 309 (1963); FERC v. Pennzoil Producing Co., 439 U.S. 508, 517 (1979).

365. 320 U.S. 591, 602 (1944).

a cost-based approach to ratemaking to a less stringent approach in certain circumstances, and rely on competition to restrain rates.[366] In *Farmers Union Central Exchange, Inc. v. FERC (Farmers Union II)*,[367] although the court rejected the Commission's generic rate-making methodology for oil pipelines in that case, the court recognized that changing characteristics of regulated industries may justify an agency's decision to take a new approach to determining just and reasonable rates. As the court stated, "[m]oving from heavy to light-handed regulation within the boundaries set by an unchanged statute can be justified by a showing that under current circumstances, the goals and purposes of the statute will be accomplished through substantially less regulatory oversight."[368] The court further explained that non-cost factors may play a role in setting rates, if the Commission specifies the nature of the non-cost factors and how they justify the rate.[369] These non-cost factors include competitive forces. As the court stated in *Wold Communication, Inc. v. FCC*,[370] an agency may allow the marketplace to substitute for direct regulation in appropriate circumstances.

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366. *E.g.*, Farmers Union Central Exchange, Inc. v. FERC (Farmers Union II), 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 1034 (1984); Wold Communication, Inc. v. FCC, 735 F.2d 1465, 1475 (D.C. Cir. 1984).

367. 734 F.2d 1486 (D.C. Cir. 1984).

368. *Id.* at 1510.

369. *Id.* at 1503.

370. 735 F.2d 1465, 1475 (D.C. Cir. 1984); *see also* FCC V. WNCN Listeners Guild, 450 U.S. 582 (1981) (approving FCC reliance on market forces in entertainment programming); Western Union Telegraph Co. v. FCC, 674 F.2d 160 (2d Cir. 1982) ("newly unleashed market forces" may be a reasonable substitute regulatory tool).

The Commission's action here falls within its discretion, as discussed in these decisions, to change its regulatory methods to allow the marketplace to substitute for direct regulation of sales for resale rates. Consistent with *Farmers Union II*, in the final rule, the Commission identified and discussed in detail the changed conditions in the industry that warrant less oversight of sales rates.[371] As discussed more fully below, the Commission found that, with full open access transportation, pipeline *sales markets* are or will be sufficiently competitive to prevent pipelines from exercising monopoly power. The Commission reached this conclusion because, under the final rule, pipelines will offer transportation on an equal basis for all gas supplies and because adequate gas supplies exist throughout the nation from a wide variety of sellers. And this approach puts the pipelines as merchants on the same basis as other sellers of gas now are, *i.e.*, they have the ability to sell gas at market-based rates.

The final rule puts into effect on an industry-wide basis for natural gas sales, the approach to rate regulation that the Commission has adopted recently on a case-by-case basis. In several recent decisions, the Commission approved market-based unbundled sales rates where the Commission found the market to be sufficiently competitive to prevent the pipeline from exercising monopoly power and to keep rates at a just and reasonable level.[372] In *Transwestern Pipeline Co.*,[373] the Commission approved the pipeline's proposal for market-based rates for unbundled sales service because those sales were made in the wellhead market which Congress sought to deregulate.

371. Order No. 636 at p. 30,394-406, 30,408-13, 30,437-41.

372. *See* Order No. 636 at p. 30,439 n.213.

373. 53 FERC ¶ 61,298 (1990).

Appendix C

Again in *El Paso Natural Gas Company*,[374] the Commission approved a settlement providing for market-based rates for unbundled sales. The Commission found that approval of these rates was consistent with its responsibility to assure that rates are just and reasonable. The Commission explained that in the NGPA, Congress determined that the sales market for gas at the wellhead is competitive and that Congress specified that the price of gas sold in that market is just and reasonable.[375] The Commission found that there are adequate divertible supplies of gas in the markets that El Paso serves and that El Paso sales would compete with deregulated sellers in the wellhead market. The Commission concluded that the competitive wellhead market would force El Paso to charge rates at or below the rates of its wellhead competitors, and, therefore, that the market would operate to keep El Paso's unbundled sales rates at a just and reasonable level.[376] Based on the Commission's findings in these proceedings and on its analysis of the current gas sales market discussed in Order No. 636 and below, the Commission has concluded that its policy of relying, to the maximum extent possible, on competitive market forces to balance the supply and demand for natural gas at reasonable prices should be extended to all sales markets.[377]

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374. 54 FERC ¶ 61,316, *reh'g granted in part*, 56 FERC ¶ 61,290 (1991).

375. § 601(b) NGPA, 15 U.S.C. § 3431(b).

376. *See also* Transcontinental Gas Pipeline Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991).

377. In addition, in Buckeye Pipe Line Company, a case involving oil pipeline transportation rates, the Commission held that clearly identified non-cost factors such as competition or a lack of market power warranted departure

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Appendix C

In arguing that the Commission has exceeded its authority, APGA relies on *Maislin Industries, U.S. Inc. v. Primary Steel, Inc.*,[378] where the Supreme Court stated that, although the agency had the experience and expertise generally to adopt new policies when faced with new developments in the industry, "it does not have the power to adopt a policy that directly conflicts with its governing statute." In *Maislin*, the Court rejected an agency decision that was a direct violation of the filed rate doctrine, was contrary to over a century of case law, and permitted the very type of price discrimination that the statute was intended to prevent.

In the Commission's judgement, the situation here is quite different. The final rule does not directly conflict with any statutory mandate. Indeed, the final rule furthers statutory goals by moving toward less stringent regulatory oversight of sales rates within the bounds of the statute. The NGA specifically envisions that individualized contracts will provide terms and conditions for the sale of gas[379] and this rule returns to reliance on individualized contracts to determine the price provision.

In addition, APGA cites *FPC v. Texaco*,[380] as supporting

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from traditional rate review when the substitute ratemaking methodology ensures that resulting rate levels are justified by non-cost factors. 44 FERC ¶ 61,066 (1988), *reh'g denied*, 45 FERC ¶ 61,046 (1988). In the area of electric rates, the Commission has also adopted market based pricing when the electric company lacks market power. *E.g.*, Enron Power Enterprise Corp., 52 FERC ¶ 61,193 (1990).

378. 497 U.S. 116 (1990)

379. United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1955).

380. 417 U.S. 380 (1974).

the proposition that the Commission cannot rely solely on market forces to assure that pipeline rates are just and reasonable, non-discriminatory, and non-preferential. In that case, the Supreme Court, in providing guidance on remand, stated that in its view, the prevailing price in the market cannot be the final measure of a just and reasonable rate. That decision was rendered, however, before enactment of the NGPA and the Decontrol Act. As the Commission has explained, those statutes have changed the nature of the wellhead market and its effect on competition in the pipeline sales market. In any event, the Commission is not simply allowing the prevailing market price to be the determinant of just and reasonable rates. As discussed below, the Commission will monitor the operation of the market through reporting requirements and the complaint process. In addition, the Commission is continuing to regulate jurisdictional transportation on a cost basis.

APGA and Gas Company of New Mexico also cite *Mid-Louisiana Gas Co. v. FERC*,[381] as standing for the proposition that the agency must administer its statute, and may not alter the statutory scheme, even if its alteration is an improvement. In addition, these parties cite *Public Service Comm'n of New York v. FPC*,[382] as holding that where Congress has prescribed regulation, the agency may not "abandon [its] responsibility by acquiescing in a charade or rubber stamping of non-regulation in agency trappings."[383] The Commission has not altered the

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381. 664 F.2d 530, 535 (5th Cir. 1981), *vacated and remanded on other grounds*, Public Service Comm'n of New York v. Mid-Louisiana Gas Co., 463 U.S. 319 (1983).

382. 511 F.2d 338, 354 (D.C. Cir. 1975).

383. APGA also cites Texaco, Inc. v. FPC, 474 F.2d 416, 423 (D.C.

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statutory scheme, but, as explained more fully below, has changed its regulatory methods to police the functioning of the market.

2. Adequate Divertible Supplies

APGA, Citizen Action, Marathon, and State of Michigan argue that the Commission's finding that adequate divertible supplies of gas exist in all markets is not based on substantial evidence. APGA and Marathon assert that there is no record evidence to support this finding. Instead, they argue, the Commission merely concluded generically that, at present, gas supplies in the United States exceed demand and relied on the Decontrol Act. APGA alleges that the Commission made no study of specific gas supply markets, and made no specific findings that there is competition between pipelines and third party suppliers to supply the peaking requirements of temperature sensitive loads. Marathon asserts that a finding of divertible gas supplies on individual pipelines cannot be "scaled-up" to justify an industry-wide finding.

The Commission's finding that there are adequate divertible supplies of gas is based, not only upon its findings in the specific cases discussed above,[384] but also on a detailed analysis of

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Cir. 1972), *vacated and remanded on other grounds*, 417 U.S. 380 (1974), for the same proposition, *i.e.*, that only Congress and not the agency can deregulate.

384. As discussed above, the Commission engaged in a detailed analysis of the gas sales markets in the Transwestern, El Paso, and Transcontinental proceedings.

conditions in the natural gas market.[385] The order relies on the Staff Study on Interim Gas Supply Charges and Interim Gas Inventory Charges, Notice of Proposed Policy Statement, "Use of Spot Market Prices for Sales Service and Gas Inventory Charges."[386] In that study of the national spot market, Staff concluded that the natural gas spot market is a well functioning market in the sense that it is broad, and prices indicate its responsiveness to supply and demand. In addition, Order No. 636 discussed the Staff study on market centers, Importance of Market Centers, Office of Economic Policy, FERC, August 21, 1991).[387] These studies of the natural gas sales market support the Commission's conclusion that there is a significant amount of uncommitted natural gas at competitive prices throughout the country.[388] Further, as part of its analysis, the Commission explained that in passing the NGPA and the Decontrol Act, Congress found that gas sales at the wellhead, or in the field, are competitive.

Thus, the Commission's finding that adequate divertible gas supplies exist in all markets is fully supported by the record in this proceeding. None of the parties has offered any specific evidence to the contrary. Moreover, as discussed more fully below, the Commission has provided parties an opportunity to challenge this generic finding with regard to a specific pipeline in the individual restructuring proceedings.

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385. *See* Order No. 636 at p. 30,394-406, 30,408-13, 30,437-41.

386. Order No. 636 at p. 30,396 n.41, *citing* 47 FERC ¶ 61,294 Appendix at 62,036-62,040 (1989).

387. Order No. 636 at p. 30,427 n.145.

388. Order No. 636 at p. 30,440.

Marathon also argues that the Commission presented no economic theory or legal justification for its conclusion that the existence of adequate divertible supplies *ipso facto* equates to a lack of market power. Contrary to this assertion, the Commission has explained the legal and economic basis for concluding that the existence of adequate divertible supplies of natural gas will prevent the pipeline from exercising market power over unbundled sales. With high quality, open access, firm transportation available, sellers of uncommitted gas supplies will be able to compete with pipeline sales and, as a result, it will not be profitable for a pipeline to attempt to expand its market power over transportation into sales. Pipelines will have to charge rates that compete with the rates of their unregulated competitors, and their rates will be constrained by the rates of their wellhead competitors at a price that Congress has declared to be just and reasonable.[389]

State of Michigan asks the Commission to clarify what it means for a market to be "sufficiently competitive." Further, State of Michigan asserts that while divertible supplies may exist in the current market, they may not exist in the future.

In the final rule, the Commission stated that a pipeline's sales are made in a sufficiently competitive environment when the pipeline provides transportation service of equal quality with respect to all gas supplies, from whomever purchased, and when adequate divertible gas supplies exist.[390] The relevant determination is whether the pipeline is able to exercise market power by controlling prices or excluding competition. A pipeline has significant market power if it can maintain its price above

389. § 601(b) NGPA, 15 U.S.C. § 3431(b).

390. Order No. 636 at p. 30,403 n.71.

the competitive level and obtain a monopoly profit.[391] A market is sufficiently competitive if it prevents the pipeline from exercising market power and operates to keep rates at a just and reasonable level.

The final rule is based on an assessment of present market conditions. It is not necessary for the Commission to find that there will be adequate divertible supplies forever into the future in order to substantiate that the natural gas sales market is competitive. Although the Commission cannot guarantee that demand will never exceed supply, a properly functioning market is the best method for correcting such shortages through changes in the price of gas. And more importantly, the Commission's past price control over the gas commodity was equally no guarantor of "adequate divertible supplies forever."[392] The regulatory approach adopted here permits the Commission to monitor the gas sales market and take corrective action if necessary.

3. Small Customer Rate

APGA and Citizen Action argue that the Commission should impose a price cap on the market-based rates.[393] Industrial Groups argue that before instituting market-based pricing, the Commission should provide for a two-year transition period.

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391. *See* El Paso, *supra*, 56 FERC at 62,175 (1991).

392. *See, e.g.*, Federal Power Commission Order No. 467-B, 49 FPC 583 (1973) (establishing procedures for curtailments during gas shortages).

393. These parties note that even the FCC, when it found that ATT operated in a fully competitive environment, instituted price cap regulation rather than total deregulation.

In addition, APGA argues that even if the market is competitive as to large buyers, the Commission cannot make such a finding as to smaller LDCs on the basis of the record in this proceeding. APGA maintains that the Commission made no finding that there are adequate supplies and adequate competition to serve small sales customers, who have traditionally had fewer gas supply options. APGA further asserts that the Commission could not make this finding based on a full record in the El Paso global settlement, and therefore cannot do so here. Moreover, APGA argues, the Commission has improperly placed the burden of proof on the small LDCs to challenge this finding in the restructuring proceedings, when the burden should be on the pipelines to show that adequate divertible supplies exist to meet the peak-day needs of these customers. Citizen Action maintains that the Commission failed to address the issue raised in the comments on the proposed rule that there is no real competition between pipelines and third party suppliers to supply firm peaking gas.

In the El Paso proceeding cited by APGA,[394] which involved a GIC to be applied only to the pipeline's five largest customers, the competitiveness of the market with respect to small LDCs was not relevant to the issues before the Commission and, therefore, no findings were made as to the competitiveness of that market.[395] The Commission believes that small customers can benefit from purchasing gas in the competitive market as well as large customers. For example, at the technical conference held on January 22, 1992, Florida Cities pointed out that small customers can band together to purchase gas. In Florida, several

394. 54 FERC ¶ 61,316 (1991), *reh'g granted in part*, 56 FERC ¶ 61,290 (1991).

395. *Id.* at 61,945-46 (1991)

municipal utilities banded together with one party buying on behalf of others. The Florida Cites representative at that technical conference reported to the Commission that those utilities have achieved "tremendous economies and urged the Commission to complete the transition to fully unbundled services."[396]

Nonetheless, the Commission recognizes that small customers may require a transitional period to adjust to purchasing gas at negotiated prices. For a one-year period after the effective date of the blanket certificate, the Commission will require pipelines to offer to sell gas to the small customers on their system at cost-based rates. This means that if the customer chooses, the pipeline is obligated to sell gas under the blanket certificate to the small customer on a cost basis for one year from the effective date of the pipeline's blanket sales certificates issued pursuant to Section 284.284. Small customer is defined, for the purposes of this provision, as a customer that purchases gas under the pipeline's one-part imputed load factor rate schedule on the effective date of the blanket certificate. The small customer must exercise this transitional option to purchase gas at a cost-based rate in the restructuring proceeding and not at a later time within the one-year period.

The Commission will not adopt a particular small customer pricing method, but will leave the development of this mechanism to the parties in the restructuring proceeding. There are a number of ways the parties could develop cost-based rates for sales to small customers. For example, the parties could devise a small customer rate using the spot price index. The pricing mechanism could provide that the sale price to small customers would be equal to the spot price plus a fixed amount,

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396. Technical Conference Tr. 277, 291-92, 293. Order No. 636 at p. 30,411.

with the price capped at cost.[397] Alternatively, the parties could provide for periodic adjustments to the sales rate, without reference to a pricing index, by establishing a fixed rate that is adjusted periodically to reconcile any difference between that rate and the pipeline's actual gas costs. The Commission, however, will not permit the continued use of the existing PGA mechanisms for this purpose. The accounting and filing requirements of those mechanisms, as well as the detailed Commission review, are far more complicated than necessary for this one-year transitional measure. Another, simpler alternative would be for the pipeline to establish a fixed gas cost rate for the small customers, without any adjustments during the year, based on a projection of the pipeline's actual gas costs for the year. Or, the parties could agree to a "most favored nations" pricing provision so that the small customer's rate is equivalent to the negotiated price at which the pipeline sells to other customers.[398]

Whatever method the parties choose for establishing the cost-based rate, the pipeline is required to include the method in the tariff sheets filed as part of its compliance filing in the restructuring proceeding. However, this provision will terminate automatically after the one year transition period. Also, regardless of the mechanism the parties develop to establish rates for small customers, sales to small customers must be unbundled. However, as explained above, a customer can contract with the pipeline for the pipeline to act as the customer's agent in packaging the separate services.

The purpose of this limited transitional measure is to allow

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397. See Transwestern Pipeline Company, 55 FERC ¶ 61,519 (1991), for an example of this approach.

398. *See* El Paso Natural Gas Co., 54 FERC at p.61,958.

small customers additional time to make alternate supply arrangements, for example, to arrange to aggregate their purchases. Some municipal LDCs may need to obtain authorization from their state legislature to join into alternate purchase arrangements. The one-year transition period (from the effective date of the pipeline's blanket certificate) will afford these customers sufficient time to determine what alternate arrangements are best suited to their needs and to take measures to implement these arrangements. As a practical matter, this provision will give the small customers a transition period of two winter heating seasons to make these arrangements because the implementation schedule makes it unlikely for most pipelines to have a blanket sales certificates that is effective during the 1992-1993 heating season. The blanket certificate issued under section 284.284 of the regulations requires the pipeline to continue sales to its sales customers if they choose to purchase from the pipeline for the duration of their existing contract term, and the provision adopted here establishes that these sales will be capped at cost to the small customers for a one-year transition period. This certificate authority for sales with cost-based rates to small customers, and any associated tariff provisions, shall terminate automatically at the end of the twelve-month period on a self-executing basis. If, at the end of the one-year period, a small customer must still obtain state legislative action or approval to enter into alternative purchase arrangements (for example, to join a gas procurement cooperative), the small customer may petition the Commission for an extension of the certificate authority for sales to it with cost based rates by the pipeline for a period up to an additional twelve months. The extension would allow the small customer additional time to seek such legislative action or approval during the next scheduled session of its state legislature. Other parties, including the pipeline, will be provided an opportunity to respond to such a petition.

Appendix C

It should be observed that a cost-based rate cap may not afford the small customers the protection they believe will occur. Under the NGPA, pipelines are guaranteed passthrough of actual costs, and experience has shown that the pipelines' regulated resale rates, through the PGA, have been above the market price. As the Commission explained in Order No. 636, purchasers of gas from pipelines have been disadvantaged under the current system. The price that pipelines charge for gas has been 20 to 80 cents higher per mcf than the rates available from other sellers. The so-called protections of traditional cost-based rate regulation have become less significant in the more competitive environment where the market operates to keep prices at a competitive level. Hence, the Commission believes that small customers will be better off purchasing gas under the revised regulatory regime of Order No. 636 than under the current regulations. However, given the limited resources many small customers have, the Commission finds it reasonable to allow this transition mechanism.

With regard to other sales customers, the Commission finds that competition in the market monitored by the reporting requirement and the complaint process will assure that rates are at a just and reasonable level. Therefore, the Commission finds that a general rate cap for all sales, or a general transition period for all customers, is not necessary.

In sum, the provisions of this rule, taken together, will assure that small customers will have access to gas supplies at the lowest reasonable prices. For a one-year transitional period, gas supplies can continue to be purchased from the pipeline at cost-based rates (to the extent the small customer chooses to do so.) However, the small customers will have the opportunity to obtain even better prices in the market. Under the capacity releasing

provisions,[399] customers will be able to obtain the transportation capacity necessary on connecting pipelines to connect them with a source of gas at the wellhead. During the restructuring proceeding, the pipeline that has been providing these customers with bundled sales service will be required to assign its converting upstream firm transportation capacity to its firm transportation customers. This includes the small customers, who can obtain the firm rights to any capacity necessary to give them a direct path to the production area. In addition, after the restructuring period, the provisions of Section 284.243 will give small customers flexibility (acting alone or together, or through a representative) to obtain additional released firm capacity on other pipelines or segments for access to a variety of sources of supply as they become available. Thus, the rule provides sufficient flexibility and safeguards to assure continued reliable service to small customers at reasonable rates.

4. Regulatory Safeguards

Marathon asserts that in order to assure that light-handed regulation achieves statutory goals, the courts have required certain safeguards. Marathon argues that the Commission erred in failing to provide adequate safeguards to assure that rates will fall within a zone of reasonableness, and failing to provide for an administrative remedy if they do not.[400] Marathon asserts that the complaint procedure is not an adequate safeguard

399. Sections 284.242 and 284.243.

400. Marathon cites, *inter alia*, Public Service Company of Indiana, 51 FERC ¶ 61,367 at 62,223 (1990) (where the Commission stated that the Farmers Union II court found that the flaw in the Commission's market based regulation was that "nothing in its regulatory scheme would act as a monitor either to determine whether competition would drive prices down ... or to check rates if it did not.").

because it places the burden of proof on the party challenging the rate, and because the Commission cannot execute its responsibilities by relying on contesting parties to bring problems to the Commission's attention.[401] Similarly, Northern Distributor Group argues that section 5 is not an effective remedy because of regulatory lag and the prospective nature of the section 5 remedy.

While the Commission has found that market-based rates are appropriate for pipeline sales, the final rule recognizes that there may be some isolated markets that are not sufficiently competitive to support a finding that a particular pipeline lacks significant market power. Thus, the Commission stated that the parties may raise the issue of a particular pipeline's market power in the restructuring proceedings. If a party to the restructuring proceedings demonstratesthat the pipeline has significant market power over the sale of gas, the Commission will employ more regulatory control, if the pipeline does not rebut this evidence showing. The market-based rates will not be put into effect prior to a Commission examination of a party's argument, so refunds are not an issue in the restructuring proceedings.

If competitive circumstances on the pipeline change, a customer may file a complaint under section 5 of the NGA to show that the pipeline has attained market power and that greater regulatory control is needed. As Marathon notes, in a section 5 proceeding, the complainant has the burden of proof, remedies are prospective only, and no refunds can be ordered. This, however, has always been part of the regulatory scheme as enacted by Congress, and does not render section 5 ineffective as a remedy. The issue of market power will first be examined

401. Marathon cites Tejas Power Corp v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

in the restructuring proceedings, if raised by the parties, and in the event of changed circumstances, the section 5 procedure is available to an aggrieved party.

Marathon also argues that the Commission has essentially established a rebuttable presumption that all pipelines lack market power, and that this presumption improperly shifts the burden of proof to the contesting party in the restructuring proceedings. Marathon argues that this "ignores the Commission's market power findings in the incentive rate docket and its recent decision to open an investigation of deregulated pipeline transportation." Marathon asserts that in both cases, the Commission observed that market power is an unsettled, largely unexplored issue.

Contrary to Marathon's characterization, the Commission has not instituted an investigation of deregulated pipeline transportation. Instead, a task force has been established to consider how to evaluate competition in transportation markets. Both the task force and the incentive rate proceeding referred to by Marathon involve transportation, not sales, rates. Nothing in the Commission's proposed policy statement on incentive ratemaking[402] or the establishment of a task force on competition in transportation markets evaluates competition in the natural gas sales market or conflicts with the finding that pipelines lack market power over sales of gas.

In addition, Marathon argues, this procedure is inconsistent with the Commission's approach in electric utility cases where

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402. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, Docket No. PL92-1-000, issued March 13, 1992, 58 FERC ¶ 61,287 (1992).

the Commission has required the utility to show that it lacks market power. Since the Federal Power Act and the NGA must be read *in pari materia*, Marathon argues, the Commission must provide a reasoned explanation for departing from its electric utility precedents.

Precedent under the Federal Power Act is relevant to NGA proceedings. However, the electric transmission market has characteristics very different from the natural gas sales market. Electric transmission, like natural gas transportation, has characteristics of a natural monopoly, and competition may not be as effective to restrain prices. Thus, the Commission's approach in electric cases, *i.e.*, an individual inquiry into market conditions in each rate proceeding, is appropriate.

In the natural gas sales market, however, the Commission has found that pipelines no longer have a monopoly over the sale of gas. There are other sellers and marketers of gas in the marketplace, and in order to meet that competition, the pipeline will have to charge rates at or below the prices of its wellhead competitors.

Finally, Marathon asserts, the rebuttable presumption is defective because the pipeline is the party in possession of the necessary facts to show lack of market power, and, consistent with evidentiary principles,[403] should bear the burden of proof. While the pipeline is in possession of the facts concerning its own operations, it does not follow that it should bear the burden of proof on all issues where that information is relevant. If that were the case, the pipeline would bear the burden of proof on every issue in rate cases, but that is not consistent with the

403. Marathon cites, *inter alia*, XI Wigmore on Evidence § 2486, p. 290.

scheme under the NGA. Moreover, facts concerning adequate divertible supplies would not necessarily be within a pipeline's exclusive possession. The data exchange process established by the Commission will permit the parties to obtain information necessary to substantiate their market power claims.[404]

Marathon also argues that the rule is ambiguous as to what the contesting party must prove. Marathon asks the Commission to clarify that the parties will have a full opportunity to challenge anticompetitive sales and show that the pipeline possesses market power, including market power derived through inadequate divertible gas supplies.

The Commission did not intend to limit the matters the parties may raise in the individual restructuring proceeding and clarifies that the parties may address market power based on inadequate divertible supplies as well as on other conditions. However, the Commission will defer the issue of specific evidentiary standards to case-by-case resolution.

Industrial Groups argues the Commission should review tariff sheets filed by each pipeline to determine whether rates are just and reasonable in accordance with Order No. 636 standards. Similarly, APGA, ConEd, Michigan Gas, NYSE&G, Northern Distributor Group, New York PSC, Peoples Gas, and the State of Louisiana argue that the Commission should require as part of the less intrusive regulatory scheme, that pipelines file a rate case every three years to evaluate the justness and reasonableness of unbundled sales and transportation rates. Without this requirement, Northern Distributor Group argues, light-handed regulation becomes deregulation.

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404. See the order issued June 24, 1992 in Docket No. RM91-11-000, granting in part the motion filed by Natural Gas Clearinghouse to establish discovery procedures. 59 FERC ¶ 61,351 (1992).

As discussed more fully below, the Commission will not require the pipelines to file a new rate case every three years. The statute does not require such a filing, and Commission finds no basis for imposing this requirement.

5. Other Matters

Columbia asks the Commission to clarify section 284.14(d)(2) of the regulations which provides that a pipeline may abandon its sales obligations to any purchasers to the extent "[t]he purchaser refuses to pay the rate the pipeline offers for unbundled sales." Columbia maintains that it reads this section as giving pipelines the ability to offer rates that in their sole discretion adequately compensate them for their remaining merchant function. Columbia asks the Commission to clarify that it will not intervene and set a sales rate for a pipeline if any purchaser insists that a pipeline remain a merchant, but refuses to pay the rates proffered by the pipeline.

Columbia's request for clarification is granted. The pipeline will determine whether it wants to sell gas at a particular rate, with the limitation that rates to small customers must be cost-based for a one-year transition period. However, as explained above, the pipeline is subject to the provisions of the NGA, and the Commission will address a customer's complaint that the pipeline is violating the statute.

Tenneco asks the Commission to clarify that pipelines have no more obligations with respect to the sale of gas than other gas merchants. Specifically, Tenneco asks the Commission to clarify that pipelines are free to negotiate all the terms of their sales contracts, and that differences in terms of sales contracts will not constitute undue discrimination.

Individualized contracts between pipelines and customers

are permitted under the NGA,[405] and competitive conditions may justify different contractual terms for sales service. However, the pipeline is still subject to the NGA requirement that pipelines must provide service on a non-discriminatory basis. Thus, similarly situated customers must be treated similarly.

Further, Tenneco argues that there is no justification for the Commission's requirement that pipelines perform agency services on a non-discriminatory basis. Tenneco states that non-pipeline sellers are not required to offer agency services on a non-discriminatory basis, and that there is no evidence that customers desiring agency service will find any shortage of sellers willing to provide this service. Further, Tenneco argues, imposition of this requirement on pipeline sellers, when no such restriction exists for non-pipeline sellers, gives non-pipeline sellers an unfair competitive advantage, and thus harms the unfettered competitive market the Commission is trying to foster.

Tenneco's argument ignores a critical difference between pipelines and non-pipeline merchants: the pipelines are in control of the operations of the transportation grid and they are, simply put, different from other merchants, since they are the only merchants in control of pipeline capacity. Pipelines are still subject to the NGA and may not unduly discriminate among customers. Pipelines are encouraged to offer an agency service, and this service must be offered on a non-discriminatory basis. Competitive circumstances, however, can justify differences among customers.

Further, Tenneco urges the Commission to clarify that if market-based pricing is not approved by a reviewing court for

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405. United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956).

any reason, then the basis of the entire rule is no longer applicable. Tenneco's request is denied. The Commission will not speculate what action it might need to take in response to a decision by a reviewing court.

C. Standards of Conduct

In Order No. 497, the Commission adopted standards of conduct and reporting requirements for interstate pipelines with marketing affiliates.[406] These regulations implement the Commission's authority to prevent undue discrimination by prohibiting the pipeline from preferring its marketing affiliate over unaffiliated shippers with regard to transportation matters, access to information, and transportation discounts. On July 21, 1992, the U.S. Court of Appeals for the District of Columbia Circuit upheld in substantial part the Commission's decision in Order Nos. 497 and 497-A. The court found that the standards of conduct and reporting requirements are an appropriate exercise of the Commission's authority to prohibit undue preferences, but found that the Commission had not adequately

406. Inquiry into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988, FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (December 22, 1989) FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (December 28, 1990) FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (January 2, 1992) III FERC Stats. and Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (February 8, 1992, 58 FERC ¶ 61,139 (1992). The United States Court of Appeals for the District of Columbia Circuit upheld the Commission's decision in substantial part in Order Nos. 497 and 497-A in Tenneco Gas Co. v. FERC, No. 89-1768 (July 21, 1992).

explained its extension of the contemporaneous disclosure requirement to gas sales and marketing information and remanded that issue to the Commission for further explanation.[407]

Order No. 636 does not change the requirements governing the relationship between pipelines and their marketing affiliates. However, Order No. 636 extends the requirements to pipelines providing unbundled gas sales services because the pipeline as merchant will be the functional equivalent of a marketing affiliate. Requests for rehearing of this portion of Order No. 636 were filed by several pipelines[408] and other parties.[409] Generally, the pipelines argue that the Commission erred in continuing the Order No. 497 requirements and applying them to pipelines as merchants, while the other parties maintain that additional protections are required.

CNG argues that the Commission lacks authority to extend the standards of conduct to pipelines because neither the NGA nor the NGPA specifically authorizes the Commission to require the separation of a pipeline's employees or to control the dissemination of business information. However, as the Commission explained in Order Nos. 497 and 636, there is obvious potential for undue discrimination by the pipeline to favor its own merchant function or its marketing affiliate. The Commission's jurisdiction to remedy undue discrimination is broad and is not limited to specific measures set forth in the

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407. The Court also found that the Commission erred in finding Order No. 497 applicable to Ozark Gas Transmission System (Ozark).

408. Alabama-Tennessee, Arkla, CNG, K N Energy, Natural, Northwest, Tenneco, and Texas Gas.

409. Hadson and IPAA.

NGA or the NGPA.[410] In any event, the court's decision in *Tenneco* v. *FERC* largely answers CNG's jurisdictional argument and establishes that these regulations are within the scope of the Commission's authority.

Further, CNG argues, even if the Commission had authority to impose the requirements, it would need a factual basis to justify their adoption. CNG, Alabama-Tennessee, Arkla, K N Energy, and Tenneco argue that there is no finding based on substantial evidence that anticompetitive practices exist now or will after the restructuring. The parties assert that the Commission's concern that pipelines would favor their own sales is inconsistent with the Commission's finding that pipelines cannot exercise market power over sales and that all sellers will compete on an equal footing after restructuring. Tenneco argues that the rule will not be necessary after restructuring because the Commission's regulations will prohibit discrimination, and because matters addressed in the restructuring proceedings, including nondiscriminatory terms and conditions for unbundled transportation, allocation of receipt and delivery point capacity, and the electronic bulletin board will ensure that pipelines cannot give the merchant arm or their marketing affiliate any undue preference. Similarly, Alabama-Tennessee argues that there is no need for this protection because transportation is rapidly becoming the dominant pipeline service. K N Energy argues the Commission should modify the rule to provide that the standards of conduct will not apply unless the Commission finds that the pipeline is acting in a discriminatory manner.

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410. *E.g.*, FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972),; FPC v. Conway Corp., 426 U.S. 271, 279 (1976); Colorado Interstate Co., 324 U.S. 581 (1945), Associated Gas Distributors v. FERC, 824 F.2d 981, 997-1001 (D.C. Cir. 1987).

Appendix C

In explaining the need for the standards of conduct in Order No. 497, the Commission pointed to the potential for abuse, actual instances of anticompetitive practices, and allegations of unlawful practices that had come to its attention. The Commission concluded that the pipelines have economic incentives to show undue preferences toward their affiliates and the court has agreed that this warranted Commission action.[411] Unbundling, as required by Order No. 636 does not eliminate the potential for pipelines to favor their marketing affiliate because, as the Commission explained in Order No. 636, there is no change in the pipeline's control of the transportation function. Further, the same potential for abuse exists with regard to the pipeline merchant function and it is therefore appropriate to apply the standards of conduct to pipelines exercising the merchant function.

The Commission recognizes, however, that abuses in the area of marketing affiliates might not be a perpetual problem, and that increased competition that will result after unbundling may reduce the incentive for abuse. Order No. 497 adopted a sunset provision specifying that the Commission's reporting requirements would expire after one year unless reauthorized. The Commission has extended the sunset date of the regulations three times because it found that Commission monitoring was still necessary. As discussed below, the Commission intends to address this issue in the near future.

Several pipelines argue that the regulations would impose severe administrative, logistical, and financial burdens on the pipelines and would place them at a competitive disadvantage with respect to other sellers of gas. CNG focuses on the

411. Order No. 497, FERC Stats. and Regs. [Regulations Preambles 1986-1988] ¶ 30,820 at p. 31,129 (1988), *aff'd* Tenneco v. FERC,*supra*.

requirements that pipelines must make available to all potential shippers any information it gives an affiliate regarding transportation matters and that the pipeline must, to the maximum extent practicable, provide for the independent functioning of operating and marketing personnel. CNG alleges that this could require dissemination of virtually all routine information and require that the pipeline divest itself of in-house sales, in effect driving the pipeline out of the marketing business. The pipelines argue that this deprives consumers of the advantages of integrated firms. Tenneco alleges that the rule would require pipelines to divulge sensitive information.

The regulations are not unduly burdensome on pipelines, but instead establish an appropriate balance between the benefits of integration and the potential for anticompetitive abuses. Contrary to the pipelines' contentions, the regulations will not require the dissemination of all routine business information or sensitive information or drive the pipelines out of the merchant business.[412] In Order No. 497, the Commission specifically rejected a proposal to require pipelines to divest themselves of their marketing affiliates and instead adopted a more flexible standard that, as explained below, permits compliance to conform to the particular characteristics of the individual pipelines.

Arkla argues that the standards adopted by the Commission are too vague because they do not give notice to the pipeline of

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412. For example, a pipeline could avoid the possibility of being required to divulge sensitive information by separating its sales operations from transmission operations and requiring that the sales operating unit obtain all of its information about service from the electronic bulletin board. This would place the sales operating unit on exactly the same footing as any other seller.

what is permissible. Arkla asserts that the Commission never provided workable standards for its marketing affiliate rule and makes the same error here. Hadson similarly argues that while the rule requires operating employees of the pipeline transporter and the unbundled merchant to function independently to the maximum extent practicable, it does not define "operating employees," "function independently," or "maximum extent practicable."[413]

The standard adopted by the Commission is designed to permit individual variations in compliance appropriate to the particular characteristics of the pipeline. The application of these standards to the particular pipelines will be considered in the restructuring proceedings. As the Court held in *Tenneco v. FERC*, this does not render the standard impermissibly vague.

Northwest is concerned that the regulations governing no-notice service may have the effect of requiring pipelines to offer sales and become bound by Order No. 497 when they have no desire to engage in sales. In addition, Northwest and Tenneco argue the rule could subject pipelines who are engaged in sales to a few small distributors or as back-up to no-notice service to unnecessary and overly burdensome regulation.

These concerns are unfounded. As explained above, a pipeline is not required to continue providing unbundled sales service if its current bundled sales customers do not request and contract for unbundled sales service, nor is the pipeline required to offer sales service incidental to its no-notice service. Further, as explained below, if a pipeline engages in minimal sales, it can seek a waiver of the requirements.

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413. Hadson notes that it argued in its brief to the court in Tenneco v. FERC, No. 89-1768 (D.C. Cir.) that the failure to define these standards will create problems.

Appendix C

Alabama-Tennessee asserts that, as a small pipeline, it would have to hire additional employees and establish separate and duplicate facilities which could drive it out of the merchant business. Alabama-Tennessee states that the possibility of waivers, as in *Northern Border Pipeline Co.*,[414] will not provide a remedy because even the reduced requirements approved there would be burdensome. It argues that small pipelines should be exempt from the requirement.

As explained in Order No. 636, small pipelines have the same potential for favoring their own sales as do large pipelines, and a general exemption from the requirements for all small pipelines is not warranted. However, the flexible standard of the rule and the Commission's willingness to consider waivers of the regulations in appropriate circumstances assures that the requirements will not be unduly burdensome on small pipelines. Waivers will be considered on an individual basis and Alabama-Tennessee may seek a waiver different in scope than that granted in the *Northern Border* case, *supra*.

Unlike the pipelines, IPAA argues that additional protections are required to prevent affiliate abuse. IPAA argues that the correlative discount requirements of section 161.3(i)[415] now apply to transportation discounts, but that once a pipeline conducts unbundled market-based sales, it could avoid the requirements by selling gas at a loss while charging the maximum transportation rate to deliver the gas. IPAA asks the Commission to clarify the regulations to prevent pipelines from evading the requirements concerning correlative discounts.

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414. 55 FERC ¶ 61,262 (1991).

415. This section provides that if a pipeline offers a transportation discount to an affiliated marketer, it must make a comparable discount contemporaneously available to all similarly situated nonaffiliated shippers.

The Commission believes that IPAA's concern was adequately addressed in Order No. 636. There, the Commission concluded that "Order No. 497's standards of conduct and reporting requirements should apply to the pipeline when it provides unbundled gas sales services."[416] This included the correlative discount requirements of section 161.3(i). As part of the reporting requirements, pipelines are required to report whether affiliate marketer, or the blanket sales operating unit, sell gas below cost.[417] Also, section 250.16(g)(2) requires pipelines to maintain 24-hour public electronic access to this data. Thus, the Commission believes that pipelines will be unable to conceal such arrangements and, as a result, they should not occur.[418] And, in the unlikely event they do occur, they will be open to public scrutiny and could form the basis for action on a complaint to the Commission.

Further, IPAA asks the Commission to amend the regulations to provide that a pipeline should not discriminate between its own sales customers and its no-notice shippers who purchase from a third party. IPAA states that if capacity is preempted by no-notice service, curtailment should be

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416. Order No. 636 at p. 30,442.

417. See 18 CFR 250.16(b)(2)(xiv), which requires a pipeline subject to this rule to file a transportation log containing, *inter alia*, information about whether the affiliated marketer (or blanket sales operating unit) is selling gas at a loss.

418. However, it is important to note that the pattern suggested by IPAA is not, *per se*, a violation of the Commission's standards of conduct. An affiliated marketer (or blanket sales operating unit) may lose money on a specific sale during a specific period because it misjudged the market. A problem exists only when a pipeline grants an undue preference to an affiliate marketer (or blanket sales operating unit).

implemented in a manner which does not favor pipeline affiliate transactions. IPAA urges that this clarification will avoid numerous disputes in the restructuring proceedings.

The Commission will not address this issue here, but will require the parties to address issues related to no-notice service in the restructuring proceedings. However, Order No. 497 with regard to marketing affiliates and Order No. 636 more generally, prohibit discrimination against non-affiliates or preferences for affiliates in the operation of curtailment provisions.

The rule makes pipeline merchants subject to the reporting requirements in section 250.16 of the regulations currently applicable to pipelines with marketing affiliates.[419] Hadson notes that these requirements, by their terms, expire at the end of 1992, before the blanket sales certificates issued under the Restructuring Rule take effect. Hadson suggests that the Commission delete the current provision in section 250.16(d)(1) that eliminates the reporting requirements on December 31, 1992, at least as it relates to the reporting requirement for the instant rule.

As explained above, the Commission recognizes that the potential for anticompetitive abuses may not be a perpetual problem, and, therefore, in Order No. 497 adopted a sunset provision specifying that the Commission's reporting requirements would expire after one year unless reauthorized. The Commission has extended the sunset date of the regulations three times because it found that Commission monitoring was still necessary.[420] As noted above, the court's decision in *Tenneco*

419. 18 CFR 250.16.

420. Order No. 497-A, 54 FR 52781 (December 22, 1989) FERC Stats. (Cont'd)

v. FERC was issued on July 21, 1992, and the rehearing period has not expired. The Commission intends to extend the reporting requirements in the near future when it considers the issues on remand.

Hadson is concerned that there should be a public review process to ensure that the pipeline's procedures comply with the independent functioning standards. Hadson objects to the current process under section 161.3(j), which requires pipelines to file procedures to enable shippers and the Commission to determine how the pipeline is complying with the standards of conduct because, Hadson states, those filings are not noticed in the Federal Register or the Commission's daily orders and because the Commission has ruled that these filings are "non-adversarial." Hadson asks the Commission to resolve these problems by clarifying that (a) all filings made to demonstrate compliance with the law will be noticed in the Federal Register and the daily orders, with reasonable periods of time for members of the public to review the filings and voice facts or concerns; (b) the Commission will review the filings on the basis of a public record; and (c) the Commission will make a determination on the basis of the facts and advocacy in that public record.

The clarification sought by Hadson is unnecessary. Order No. 636 requires the pipelines to file their proposed procedures for compliance with the standards of conduct as part of their

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& Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989) Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990); Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 8, 1992), 58 FERC ¶ 61,139 (1992).

compliance filing and, therefore, the parties will have an opportunity to address these issues in the restructuring proceedings.

D. Reporting Requirements

In Order No. 636, the Commission required pipelines to file annual reports with respect to their sales under the blanket certificate, but waived the provision of section 154 of the regulations with respect to the filing of the sales prices between the pipeline and each of its sales customers. APGA, Citizen Action, and Gas Company of New Mexico allege that in modifying the reporting requirements, the Commission failed to adopt the minimum safeguard necessary to monitor the existence or abuse of market power. Gas Company of New Mexico maintains that the Commission cannot meet its responsibilities if all it receives is an annual summary of rates.

On the other hand, Tenneco asks the Commission to eliminate all reporting requirements. Tenneco argues that pipelines no longer have a monopoly over the sale of gas so it is unduly discriminatory to impose these reporting requirements only on pipeline sellers of gas.

The final rule requires all pipelines engaging in unbundled sales to file an annual report with the Commission describing the type of service provided, the total volumes sold, and the total revenues received.[421] The Commission waived the requirement that pipelines file sales prices between the pipeline and each of its sales customers. In the Commission's view, the reporting requirement added by this rule satisfies the NGA

421. Section 284.288.

requirements when the purchaser is on notice of the rate, and the amount of total revenues from each purchaser is eventually filed with the Commission as an average price as required by the reporting requirement. This information will provide an indication of how the market is functioning and whether a pipeline has been able to exercise market power.

The Commission believes that the reporting requirement plus the complaint procedure will be an effective means of monitoring the market to assure that the market functions to keep rates at a just and reasonable level. Additional reporting requirements would not aidin this process and would place an unnecessary burden on the pipelines. The most reliable indicator of whether the market is functioning to restrain rates is whether the customers are satisfied that they are receiving adequate service at reasonable rates. Where the market is not functioning to keep rates at a just and reasonable level, the Commission will consider action under section 5 to investigateand provide a remedy.

Tenneco's request that the Commission eliminate all reporting requirements is denied. As explained above, while the rule gives pipelines more flexibility to price their sales services to compete with other sellers and marketers of gas, the Commission will continue to carefully monitor the pipelines sales because pipelines control transportation.

VIII. PIPELINE SERVICE OBLIGATION (AFTER RESTRUCTURING)

Requests for rehearing of the Order No. 636 rules on pre-granted abandonment in sections 284.221(d) and 284.285 have been filed by numerous parties, including industrials, LDCs,

pipelines, and state regulatory agencies.[422] On rehearing, the Commission is modifying Order No. 636 to provide that in exercising its right of first refusal to retain capacity, a long-term firm transportation customer must match the price offered by a competing bidder, up to the maximum just and reasonable rate, and the longest contract term offered by a competing bidder, up to a maximum period of 20 years.

A. Interruptible and Short-term Firm Transportation

Section 284.221(d), promulgated by Order No. 636, authorizes pregranted abandonment of all interruptible and short-term firm transportation. The Commission explained that the nature of these services is such that customers selecting these options do not rely on continued service at the expiration of the contract. On rehearing, AGD and Peoples Gas state that while they have no objection to the application of pregranted abandonment to short-term firm transportation contracts, they ask the Commission to clarify that under the rule, a customer must actually have the option of taking long-term service. Otherwise, they argue, a pipeline could use its market power to coerce the customer into accepting a short-term contract in order to avoid giving the customer the right of first refusal.

Under Part 284 of the Commission's regulations, a pipeline

422. American Paper Institute; Industrial Groups; Reynolds Metal Company (Reynolds); APGA; AGD; Atlanta Gas; Cascade; CNG LDCs; ConEd; Elizabethtown; Illinois Power; New England Gas Distributors; New Jersey Natural; NYSE&G; Northern Distributor Group; Northern Illinois Gas; Northwest Natural Gas Company (Northwest Natural); Peoples Natural Gas; PSE&G; Tennessee and Columbia Small Customers; United Distribution Companies; Wisconsin Distributor Group; ANR; CNG; El Paso; Kern River; Natural; Citizen Action; Maryland People's Counsel; NASUCA; Pennsylvania PUC; State of Michigan.

has never been permitted to use its monopoly power to force certain customers to accept short-term service when they prefer long-term service if capacity is available to provide firm service. Withholding capacity violates the pipeline's obligation to provide transportation as embodied in section 284.8(b) of the Commission's regulations, which requires pipelines offering transportation on a firm basis to provide service "without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind."[423]

Peoples Gas also argues that priority interruptible service should receive protection from pregranted abandonment. It notes that some interruptible arrangements between a pipeline and small customers have enjoyed a special status because the Commission has found that these customers depend on these arrangements to meet peak load. Their Authorized Overrun Service from Viking Pipeline is within this group, Peoples Gas states, and has priority over other interruptible service because it is required to meet peak load. Peoples Gas cites *Viking Gas Transmission Company*,[424] where the Commission approved Viking's proposal to include a limited quantity of AOS service in its high priority interruptible service for small customers.

In the *Viking* decision cited by Peoples Gas, the Commission approved the pipeline's proposal because the record in that case showed that Viking was the only pipeline that served the requirements of these customers, that additional firm capacity was not available on the Viking system, and that these customers

423. 18 CFR 284.8(b).

424. 52 FERC ¶ 61,015 at p. 61,106 (1990).

had historically relied on purchases or transportation of interruptible gas to meet peak demands. There is no basis for concluding that these circumstances will exist on any pipeline after restructuring or that Peoples Gas will be unable to contract for firm transportation service. As explained in Order No. 636 and throughout this rehearing order, the rule will result in increased availability of firm capacity. Therefore, the Commission will not provide an exemption from pregranted abandonment for high priority interruptible service. If a customer requires high priority service to meet peak needs, then the customer should contract for firm service from the pipeline and pay the appropriate rate for firm service.

Northern Indiana Public Service Company asserts that the pre-granted abandonment of interruptible transportation could result in preferential treatment and discrimination if pre-Order No. 636 queue priorities are retained. Northern Indiana states that because the rule permits, but does not require pregranted abandonment, it could result in a pipeline's picking and choosing which interruptible shippers might be allowed to continue to use a high priority transportation or storage contract through roll- over or evergreen contract provisions because the pipeline has pre-approved unilateral abandonment rights. Northern Indiana maintains that the way to avoid this problem is to eliminate archaic queue date priority rights.

As the Commission has explained, a pipeline is not required to include a roll-over or evergreen clause in its contracts, but if it does, it must include such clauses on a non-discriminatory basis. Further, pre-Order No. 636 firm transportation queues will not be relevant in determining capacity allocation during the restructuring proceedings. The Commission believes that queues will be less important on the pipelines after restructuring because capacity should become available through the release

mechanism. Interruptible capacity will be posted on the electronic bulletin board.

B. Unbundled Sales

The Final Rule adopted pregranted abandonment for unbundled sales service and explained that a "continuing service obligation is no longer necessary to ensure LDC access to gas supply."[425] Although most parties have no objection to this provision, Marathon asserts that this is the first time the Commission has made access to gas supply the sole factor in determining whether the public convenience and necessity requires continuation of the pipeline service obligation. Marathon argues that while the Commission may change its abandonment standard, it must carefully consider and explain the need for a new standard.[426]

Marathon argues that the Commission has failed to explain why there should no longer be a distinction between private contracts and the statutory service obligation. Further, Marathon argues, while "access to gas supplies" was a major component of the public convenience and necessity in previous abandonments, it was not the only factor. Marathon asserts that the Commission has failed to explain why other factors, such as environmental impact, the presumptions of continued service, the impact on competition, and the public interest have been eliminated. Marathon does not oppose pregranted abandonment of unbundled sales, but argues that the Commission must provide a more detailed explanation of its reasoning.Similarly, Gas

425. Order No. 636 at p. 30,446.

426. Marathon cites, *inter alia*, Greater Boston Television Corp. V. FCC, 444 F.2d 841 (D.C. Cir. 1970), *cert. denied*, 403 U.S. 923 (1971); Consolidated Edison Co. of N.Y. v. FERC, 823 F.2d 630 (D.C. Cir. 1987); and Felmont Oil Corp. and Essex Offshore, Inc., 33 FERC ¶ 61,333 (1985).

Company of New Mexico argues that the Commission has failed to justify pregranted abandonment of sales. Gas Company of New Mexico cites *United Gas Pipe Line Company v. McCombs*,[427] where the Court stated that in that situation, to leave the abandonment determination in the producer's control would be "at odds with Congress' purpose to regulate the supply and price of natural gas."

Contrary to these assertions, the Commission has explained why it finds pregranted abandonment of unbundled sales upon contract expiration or termination to be permitted by the public convenience and necessity and how the factors cited by Marathon relate to that decision. As explained in the final rule,[428] this finding was based partly on the Commission's determination that sufficient gas supplies exist nationwide to prevent pipelines from exercising market power over gas supply at a contract's termination, and, therefore, that individual abandonment proceedings are unnecessary with respect to the pipeline's sales service to protect LDCs and assure continued access to supplies. The parties to a sales contract can defer pregranted abandonment by including evergreen or roll-over clauses in their contracts. In addition, the Commission's objective of creating an efficient and national gas market that protects all users of natural gas will be better served by pregranting abandonment because it will put pipelines sales on a more even, competitive basis with other suppliers. Finally, in Order No. 636, the Commission found that pregranted abandonment would have no significant environmental impact and, therefore, there is no need to consider this as a factor in authorizing service abandonment.[429]

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427. 442 U.S. 529, 539 (1979).

428. Order No. 636 at 30,446-447.

429. Order No. 636 at 30,469.

The *United Gas Pipe Line Co. v. McCombs*[430] cited by Gas Company of New Mexico is inapposite because in that case, the producer attempted to abandon service without first obtaining Commission approval under section 7(b). Here, the Commission has pregranted abandonment on a generic basis and made the required findings to support its conclusion.

C. Long-term Firm Transportation

As the Commission explained in the Final Rule, long-term firm transportation service has characteristics different from interruptible and short-term firm transportation and unbundled sales services, and, thus, the Final Rule establishes a procedure for protecting the legitimate needs of customers for continued service. First, the parties may choose to defer application of pregranted abandonment to their arrangement by including roll-over or evergreen clauses in their service contracts. Second, the right of first refusal at just and reasonable, cost-based transportation rates will protect the customer even if a roll-over or evergreen clause is not included in the contract. Under the right of first refusal, the existing customer will be able to retain service at the expiration of the contract by agreeing to match the highest cost-based transportation rate, up to the maximum rate approved by the Commission, and the longest contractual term offered by another bidder seeking the service.[431]

1. Definition of Long-term Service

The regulations governing the right of first refusal apply to firm transportation pursuant to a contract for a term of more

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430. 442 U.S. 529 (1979).

431. 18 CFR 284.221(d)(2)(ii).

than one year.[432] Industrial Groups and Northern Illinois Gas ask the Commission to amend this definition to provide that an arrangement will be considered long-term transportation if the contract is for a period of one year or more. The parties state that this is consistent with business and commercial realities and the industry procedure and billing practices. Northern Illinois Gas states that the calendar month and year are the basis for most transactions, and the introduction of partial months and carryover days is an unnecessary complication.

These requests are consistent with the Commission's intent and the Commission will amend the rule to make it consistent with industry practice. A long-term transportation service is one that is pursuant to a contract for a term of one year or more.

2. Roll-Over and Evergreen Clauses

In the Final Rule, the Commission explained that the parties can defer application of pregranted abandonment to their arrangements by including in the contract for service, an evergreen or roll-over provision. Thus, the Commission explained, in the first instance, the parties will decide whether the service obligations under the contract will be subject to pregranted abandonment.

Several LDCs, industrials, and state regulatory agencies[433] seek rehearing of the Final Rule because it fails to require pipelines to include a unilateral evergreen clause, giving the

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432. 18 CFR 284.221(d).

433. Industrial Groups; American Paper Institute; APGA; AGD; Cascade; New England Gas Distributors; Northern Illinois Gas; Northern Indiana; Northwest Natural; PSE&G; United Distribution Companies; Wisconsin Distributor Group; Citizen Action; State of Michigan.

customer the right to renew the agreement, in all long-term firm transportation contracts. These parties argue that customers, particularly small LDCs with one pipeline supplier, simply do not have the leverage to negotiate inclusion of roll-over clauses in their long-term contracts. The pipelines have market power over transportation, they argue, and have no incentive to give up the monopoly power they would have at the end of the contract. The Commission cannot rely on the availability of evergreen clauses as a justification of its pregranted abandonment proposal, they conclude, because unless such clauses are mandated, they will not in fact be a limit on the pipeline's monopoly power. In addition, Northern Illinois Gas is concerned that the pipelines could have discretion to include these clauses in contracts for incremental customers, but deny them to core customers.

Similarly, AGD asks the Commission to clarify that every firm transportation contract is deemed to carry with it an implicit mutual evergreen provision that the certificated firm transportation service will continue in the absence of notice by either party to discontinue the contract. Cascade asks the Commission to specify that a bilateral evergreen clause in a firm transportation contract of a primary term of one year or more is a contractual right to continue to receive service.

The Commission will not require pipelines to include unilateral evergreen clauses in all their long-term firm transportation contracts. Under current industry practice, evergreen clauses are frequently included in service contracts, and the Commission intended in the Final Rule to make clear that this device will remain available to parties who agree to this method of providing for continued service. However, a pipeline cannot offer evergreen provisions selectively. If it includes evergreen provisions in its contracts, it must do so on a

non-discriminatory basis.[434] Thus, the Commission finds that Northern Illinois Gas' concern is unfounded because pipelines do not have discretion to include evergreen clauses for certain customers and deny them to others.

The Commission will not find an implicit mutual evergreen clause in all firm transportation contracts and will not interpret such a clause, when included in a contract, as a right to continue service, as requested by Cascade. The Commission will not change the agreement of the parties in this way. The right of first refusal discussed below affords the protection necessary for customers that receive service under a contract that does not contain a roll-over clause.

3. The Right of First Refusal

As explained in the Final Rule, even if the parties do not include an evergreen or rollover clause in their contract, the existing customer is still assured of the right to continued service if it exercises its right of first refusal by matching competitive bids for the capacity. The effect and intent of this provision is to ensure against the inefficient or unnecessary retention of capacity at the expiration of the contract. To exercise the right of first refusal, the existing customer must agree to match the highest rate bid, up to the maximum just and reasonable cost-based rate, and the longest contract term offered by another shipper who wants the service.

a. Rate Requirement

Under the right of first refusal, in order to retain capacity, the existing customer must match the price offered by a

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434. Order No. 636 at p. 30,450 n.268.

competing bidder, up to the maximum just and reasonable cost-based rate. APGA argues that the protection afforded by capping the bidding at the maximum rate authorized by the Commission may be illusory because rates designed on the basis of SFV may be economically out of reach of many small LDCs, and the current contracts of many of these LDCs will expire after the four year mitigation period.

There is no basis for asserting that maximum rates approved by the Commission under the SFV method will be uneconomical for small LDCs. As discussed above, under the special rate provisions adopted by the Commission for small customers, small customers can continue to receive on a permanent basis unbundled transportation service under a one-part rate with an imputed load factor. Thus, rates of small LDCs eligible for this rate provision will be largely unaffected by SFV. Moreover, for customers paying rates based on SFV, Commission rate review will assure that the pipeline's rates are at a just and reasonable level; a just and reasonable rate by definition is not excessive. This argument rests on incorrect assumptions about SFV that are discussed more fully above. The cap on the bidding at the maximum just and reasonable level provides more than adequate protection that pipelines will not be able to charge monopoly rates for their service.

NASUCA asserts that, although the Commission maintains that the maximum rate will be just and reasonable, under an incentive proposal, the rate could increase without the Commission's approval and undermine the Commission's ability to assure just and reasonable rates. APGA also argues that incentive rates will compound the problem. NASUCA argues that the interplay of the right of first refusal and incentive regulation should be considered by the Commission on rehearing.

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Under the proposed Incentive Regulation Policy Statement, the Commission would not approve an incentive rate mechanism that would result in unjust and unreasonable rates. Moreover, until the Commission finalizes that proposed policy or approves an incentive rate mechanism, these claims are highly speculative.

On the other hand, ANR Pipeline argues that the right of first refusal could result in allowing customers to renew service at a rate substantially below the maximum rate, resulting in a cost shift to other customers. ANR is concerned that another shipper could bid an unrealistically low rate, even though the existing customer would have been willing to retain service at its higher rate, and all the current shipper would have to do is beat the lower offer. Similarly, El Paso asks the Commission to clarify that the rule does not mean that a customer could retain service by matching a bid that was not accepted by the pipeline, and, thus, force the pipeline to discount.

If customers were able to renew service at less than the maximum rate, as suggested by El Paso and ANR, this would merely be reflective of the competitive market. If no one bids at the maximum rate, that would mean that the capacity is valued at less than the maximum rate. However, pipelines are not required to discount under the rule and are not required to accept any offer at less than the maximum rate. If a lower bid is not acceptable to the pipeline, there is, in effect, no bid to match and, under the terms of the rule, the shipper will receive continued service at a rate, between the minimum and the maximum, negotiated by the shipper and the pipeline.

b. Length of Contract Term

A number of LDCs and several industrials and state

agencies[435] argue that the Commission erred in adopting the requirement that the existing customer match the longest contract term bid. These parties argue that the requirement will create problems for LDCs and industrials, that there is no rational basis for imposing the requirement, and that it is discriminatory and violates section 7 of the NGA.

Generally, the LDCs seeking rehearing argue that the nature of the services they provide makes it impossible for them prudently to match longer contract terms bid by competitors. AGD asserts that there is a lack of mutuality of obligation between an LDC and its customers, *i.e.*, an LDC has a public service obligation to provide gas to its customers, but the customers have no obligation to buy gas from the LDC. Therefore, the LDC runs the risk of incurring substantial stranded costs if it is forced to match a long-term bid by a competing bidder. Illinois Power and New England Gas Distributors state that because of their public service obligation, LDCs will have no choice but to match the longest bid term for capacity needed to meet their obligations. Moreover, they continue, their decision to enter into a long-term contract can be challenged on prudence grounds at the state and local level. These parties argue that while certain cogenerators and producers can enter into contracts of several decades duration, an LDC's long-term needs will change over that period; an LDC cannot and should not have to match the term bid by cogenerators and producers in order to retain capacity to meet its public service obligations and serve its human needs customers.

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435. *E.g.*, American Paper Institute; Industrial Groups; Reynolds; AGD; APGA; Cascade; CNG LDCs; ConEd; Illinois Power; NYSE&G; New Jersey Natural; Northern Distributor Group; Northern Illinois Gas; Northern Indiana; Peoples Gas; PSE&G; United Distribution Companies; Pennsylvania PUC; and the State of Michigan.

United Distribution Companies also argue that this requirement tips the balance in favor of gas producers or marketers interested in obtaining a monopoly over certain customers. If a supplier is able to take firm capacity away from an LDC shipper with a public service obligation, United Distribution Companies argue, the LDC will have no choice but to buy gas from that supplier. United Distribution Companies assert that this would shift monopoly power away from the regulated pipelines to the unregulated suppliers.

Several industrials, American Paper Institute, Industrial Groups, and Reynolds Metals, also argue that not all gas users can commit to long-term contracts. American Paper Institute asserts that the length of time for which different gas users can commit to firm transportation service is often defined by the "life" of the commodity they produce or the process or assets they use in producing it.

The right of first refusal is intended to protect existing customers, and provide them with a right to continued service, while at the same time recognize the role of market forces in determining contract price and term. Bidding on the contract term, within the limits described below, as well as price, is appropriate and is a significant part of the right of first refusal. As explained in Order No. 636, one of the goals of the rule is to permit buyers and sellers to meet in a national market place and transact the most efficient deals possible.[436] When a contract has expired, it is most efficient, within regulatory constraints, for the capacity to go to the person who values it the most, as evidenced by its willingness to bid the highest price for the longest reasonable term. Generally, long-term contracts benefit the system as a whole because they provide stability and benefits to all customers.

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436. Order No. 636 at p. 30,393.

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As explained below, LDCs are not at a disadvantage in this process because all parties have an opportunity to participate in the bidding process. Consistent with section 7 of the NGA, the existing customer has an advantage because it can always retain service by matching the highest bid.

Further, Industrial Groups argue that a customer who absolutely needs the service for two years may be forced to contract for ten years, in effect agreeing to pay far more than the regulated rate for the two years of needed service. Similarly, NYSE&G argues that long-term contracts in effect will require LDCs to pay higher than authorized rates when consideration is given to the added cost of engaging capacity longer than is needed.

No customer will ever pay a rate higher than the maximum just and reasonable rate for service, regardless of the duration of the contract. Those who value the service most should receive the capacity. If one party values the service for two years, but another potential customer values it more and bids ten years, the capacity should go to the highest bidder.

The capacity release mechanism established in the Final Rule will not solve these problems, APGA, NYSE&G, New Jersey Natural, and Northern Illinois Gas argue. NYSE&G maintains that while capacity assignment may provide some relief, it is not clear that assignees will always be available. Further, Northern Illinois Gas argues that if the LDC wants to shed the capacity in order to take advantage of more attractive rates, those rates will also attract the parties to whom the capacity might otherwise be assigned.

The capacity release program does provide a meaningful

opportunity for an existing customer to release unused capacity. It does not guarantee that all unused capacity will be sold, but it does give the customer an important means of realigning capacity to meet its needs. If a customer values the service highly enough to bid the longest term, but subsequently does not need all the capacity and is not able to find a substitute shipper, there is no reason to relieve the highest bidder of its decision to contract and shift the risk of loss to the pipeline and its other customers. The result under the rule is consistent with normal commercial practices.

Several other parties, including the State of Michigan, Illinois Power, Northern Distributor Group, United Distribution Companies, and the Wisconsin Distributor Group argue that the effect of this requirement, *i.e.*, tying up capacity for long periods of time, is actually contrary to the goals of Order No. 636. Illinois Power maintains that if an LDC is required to sign up for service for longer than is necessary, it will be unable to obtain competitive transportation or storage from a new or alternate pipeline. Similarly, Northern Illinois Gas argues that the requirement will force pipelines into long-term contracts, resulting in the inflexibility that caused the problems of the 1980's and possibly reducing the demand for natural gas. Many of the parties objecting to this requirement argue that a balance could be struck between the pipeline's need for stability and the customer's need for flexibility by placing a reasonable cap on the contract term which the existing customer must bid. AGD, Industrial Groups, ConEd, NYSE&G, New Jersey Natural, PSE&G and Wisconsin Distributor Group argue that an existing customer should be able to retain service if it meets the maximum rate bid for a term of five years. Reynolds argues that the cap should be at three years, and United Distribution Companies support a cap at between three and five years.

Northern Distributor Group believes that, consistent with the definition of long-term transportation, the term should be one year. Cascade argues that the term should be limited to 10 years, consistent with the finding in Order No. 555 that 10 years is sufficient to prove valid markets. State of Michigan also believes that 10 years is an appropriate cap.

The right of first refusal should not result in tying up capacity. Instead, it will permit the market to determine the appropriate contractual length. However, upon consideration of the parties' arguments, the Commission finds that capping the contract term that must be matched by a customer exercising its right of first refusal at a period of 20 years strikes an appropriate balance between the pipeline's need for stability, the customer's need for flexibility, and the Commission's overall goal in Order No. 636 to foster long-term, market driven arrangements in the gas industry. This cap, in the Commission's judgement, ensures that the customer obtaining the service values the service sufficiently to commit to using it for a reasonable period and provides the pipeline with a reasonable level of stability. Twenty years has been the traditional length of long-term contracts in the natural gas industry and a number of recent contracts for new capacity are for a twenty year term.[437]

c. Legal Basis

Some parties object to the right of first refusal on legal as well as practical grounds, arguing that the procedure violates section 7 of the NGA and is contrary to court decisions interpreting that section. APGA argues that the Commission

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437. *See, e.g.*, Pacific Gas Transmission Co., 56 FERC ¶ 61,192 (1991); Iroquois Gas Transmission System, L.P., 53 FERC ¶ 61,194 (1990); *reh'g granted in part and denied in part*, 54 FERC ¶ 61,103 (1991).

violates *American Gas Association v. FERC (AGA II)*[438] by not addressing the LDCs' concerns that they will have to yield to the pipeline's monopolistic demands to receive service. Further, APGA argues, the Commission erred in stating that the service obligation should first be determined by contract because this ignores legal precedent holding that a pipeline has a service obligation regardless of the contract.[439] APGA concludes that in order to comply with the requirement of section 7, the Commission must give the LDCs some reasonable protections and not make them subject to the superior buying power of others.

The right of first refusal procedure does provide protection to the existing customer and guarantees that the LDCs will not have to yield to the pipeline's monopoly power. Further, the Commission has not ignored legal precedent regarding the pipeline service obligation. Under the right of first refusal procedure, the existing customer can always retain service, but not necessarily at a discount, and not necessarily on a short-term basis, if other potential customers value the service and are willing to pay the maximum just and reasonable rate for a longer term. If there are no other bidders, the pipeline's transportation service obligation continues, and the parties negotiate a new contract. If there are other bidders, the existing customer retains service by matching the price, up to the maximum just and reasonable rate, and the longest bid contractual term. These are not monopolistic demands. They

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438. 912 F.2d 1496 (D.C. Cir. 1990); *cert. denied*, 111 S. Ct. 957 (1991).

439. APGA cites Sunray Mid-Continent Oil Co. v. FPC, 239 F.2d 97, 101 (10th Cir. 1956), *rev'd and remanded on other grounds*, 353 U.S. 944 (1957); Farmland Industries, Inc. v. Kansas-Nebraska Natural Gas Co., 486 F.2d 315 (8th Cir. 1973); and Sunray Mid-Continent Oil Co. v. FPC, 267 F.2d 471 (10th Cir. 1959), *aff'd*, 364 U.S. 137 (1960).

are contractual terms which reflect conditions in the market place. The highest rate the existing customer must match is the maximum just and reasonable cost-based rate, which by definition cannot be a monopoly rate. Nor is the longest bid contractual term a monopolistic demand, but is merely a term other competing customers will bid for the service.

Atlanta Gas also argues that the right of first refusal violates section 7 of the NGA. It asserts that the NGA requires that the Commission make a finding that the present or future public convenience and necessity permit the abandonment, and that this standard does not permit a pipeline to discontinue service to a customer simply because it cannot match an offer made by another would-be customer. Atlanta Gas argues that *Mobil Exploration and Producing Southeast, Inc. v. United Distribution Companies*[440] is distinguishable from this case because there pipeline purchasers were protected by the ability to obtain gas elsewhere, while here the Commission has not determined that the parties loosing transportation capacity will be able to obtain capacity elsewhere.

Similarly, New England Gas Distributors argue that the procedure violates the court's mandate in *AGA II*[441] because the Commission does not explain how pregranted abandonment trumps protection of consumers against the exercise of monopoly power through refusal of service at the end of the contract term. To justify the procedure, New England Gas Distributors argue, the Commission must explain why the right of first refusal protects consumers and meets the Commission's statutory obligations; they contend that this is impossible because the

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440. 111 S. Ct. 615 (1991).

441. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991).

notion of LDCs meeting better offers to retain service is inconsistent with section 7 and ignores that LDCs are public utilities with a public service obligation. Similarly, United Distribution Companies argue that the court in *AGA II* emphasized that the overriding purpose of section 7(b) is to protect consumers from monopoly power and unjustified termination of service.

PSE&G also argues that the Commission has misinterpreted the court decisions interpreting section 7(b). Both *AGA II* and *Mobil Exploration*, they argue, require a finding that the public convenience and necessity permits abandonment, and the Commission has failed to show how customers will be protected from monopoly abuses.

In Order No. 636, the Commission made a generic finding that the public convenience and necessity permits abandonment where the existing customer does not value the service sufficiently to match a competing bid. The right of first refusal will protect customers because it permits the existing customer to retain service. The pipeline is not able to refuse transportation service at the end of the contract term or to make monopolistic demands as a condition for continued service. The pipeline must continue to provide service to the existing customer if there are no competing bids for the service, and if the existing customer matches a competing bid for service, the pipeline must continue transportation service pursuant to those terms.

American Paper Institute argues that the requirement that the existing customer match the longest contractual term bid is discriminatory and violates section 7 of the NGA because the length of time to which a customer can commit is not related to public benefits of the various industries or most efficient use of capacity. American Paper Institute states that the Commission

itself has recognized that there should be no discrimination based on duration of service.[442] Similarly, APGA argues that it is error to equate those with the greatest need for service with those who can offer the longest contract term. CNG LDCs also argue that the requirement is discriminatory and distorts the bidding process by reflecting status and bargaining position rather than market forces.

The requirement is not unduly discriminatory. All parties have an equal opportunity to bid for the capacity and, consistent with section 7, if the existing customer matches the bid for the longest term, it retains the capacity. While the LDCs argue that they should have priority because they serve human needs, other customers serve human needs as well. Moreover, the most efficient use of capacity is for it to be used by the party who values it the most. The bidding requirement is intended to help allocate transportation capacity to that party.

United Distribution Companies argue that an LDC should have an express right to a hearing under section 7(b) if it certifies that the capacity is needed to serve core customers. United Distribution Companies assert that including this provision would make Order No. 636 analogous to Order No. 451, which provided that any customer faced with an unjustified loss of gas under the Order's procedures was entitled to a complaint proceeding.

The Commission's complaint procedure is always available to remedy an unjustified loss of service. A hearing is necessary, however, only if there are material facts in dispute. As the

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442. American Paper Institute cites 18 CFR 284.8(b), 284.9(b); Arkla Energy Resources, 48 FERC ¶ 61,305 at 61,985 (1989); Arkla Energy Resources, 47 FERC ¶ 61,045 at 61,131 (1989).

Commission has explained, the right of first refusal is an adequate protection for LDCs serving core customers.

d. Mechanics

Several parties ask the Commission to clarify or amend the mechanics of the right of first refusal process. ConEd asks the Commission to clarify that a long-term firm transportation customer has the right to extend service at the maximum rate for a period of more than one year where the contract expires, the pipeline gives notice of its intent to terminate, there are no competing bidders for the capacity, and the parties cannot agree to new terms. Otherwise, ConEd asserts, the pipeline could force the customer to accept a short-term contract or an unreasonably long-term contract. AGD also asks the Commission to clarify that where there are no competing bids, the firm transportation holder has a right to extend its contract for a period of more than one year, in order to protect it against pregranted abandonment.

The Commission clarifies that, when there are no competing bidders for the capacity, and the existing shipper agrees to pay the maximum rate, the existing customer is entitled to continue the transportation service for whatever term it chooses.[443] The pipeline may not withhold service at the maximum rate.[444] If there are no competing bids, the existing holder has in effect tendered the "longest" term offered for that capacity.

Elizabethtown asks for clarification of section

443. Of course, the pipeline could agree to less than the maximum rate in such circumstances.

444. Order No. 636 at p. 30,449.

284.221(d)(2)(ii) of the regulations which provides that pregranted abandonment does not apply if the individual transportation arrangement is for firm transportation under a contract with a term of more than one year, and the firm shipper:

> Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the maximum rate under § 284.7, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, *and* executes a contract matching those terms.

Elizabethtown is concerned that the use of the conjunctive in the last clause could be interpreted to mean that the shipper would experience pregranted abandonment if no one submitted a bid for the firm capacity and, therefore, no opportunity was available to the shipper to execute a contract matching an alternate bidder's terms. To avoid confusion, Elizabethtown suggests that the last clause be amended to read as follows:

> and, if such offer was made to the pipeline, executes a contract matching those terms.

To avoid confusion, the Commission will revise the regulation to avoid the construction pointed out by Elizabethtown.

Tennessee and Columbia Small Customers ask the Commission to clarify that only customers in the same rate class will bid against each other and that customers formerly receiving service under rate schedules GS and SGS need not match bids by larger customers for the same capacity. Tennessee and

Columbia Small Customers reason that because the Final Rule provides that "the maximum rate that must be matched is the highest rate the pipeline is authorized to charge for the capacity sought,"[445] if the "capacity sought" is firm transportation service that had been converted from former GS or SGS service, larger customers would not be eligible to bid. Further Tennessee and Columbia Small Customers argue, to permit large customers to bid against small customers would be grossly in equitable and inconsistent with the mitigation measures that the rule required.

Tennessee and Columbia Small Customers have misinterpreted the rule. The rule is not intended to limit the parties who may bid on capacity to those in a single rate class. However, Tennessee and Columbia Small Customers are not disadvantaged under the pregranted abandonment rule in section 284.221(d) because customers must only bid up to the maximum just and reasonable rate the pipeline can charge to them, not the highest rate the pipeline can charge for the capacity.[446]

United Distribution Companies argue that the pipeline should not have the discretion to determine what constitutes the best offer. Procedures for implementing the right of first refusal, including an appropriate method of determining the best offer must be developed in the individual restructuring proceedings, in which LDCs will be able to participate in developing the standard to be used by each pipeline.[447] However, any standard must be an objective one, based on economic factors. The Commission's intent is to permit variations by pipelines but to ensure that whatever objective standard a pipeline chooses would

445. Order No. 636 at p. 30,449.

446. *Id.*

447. Order No. 636 at p. 30,451.

be put in its tariff so that all parties would know the rules in advance.

e. Bona Fide Offers

Industrial Groups argue that the Commission should adopt procedures similar to those adopted in Order No. 451 to assure that bids are *bona fide*, *i.e.*, that bids be in writing, accepted in principle, and achieved in arm's length transactions. Northwest Natural argues that the regulations should preclude the pipeline and affiliates from submitting offers and should provide that a shipper should only have to match an offer from a non-affiliate. Northwest Natural states that this is required by the policy underlying the affiliated entities rule in the NGPA and that pipelines and affiliates should not be allowed to repackage services into anticompetitive packages.[448] Northwest Natural further argues that the Commission's rationale for not imposing the requirement is inadequate because the parties cannot in fact protect themselves through contractual provisions. The Pennsylvania PUC and New Jersey Natural argue that the matter should not be left to the restructuring proceedings without any direction from the Commission. Rather, they assert, the Commission should establish guidelines and controls.

Pipelines should adopt procedures similar to those adopted in Order No. 451 to assure that offers are *bona fide*. Additionally, with regard to potential affiliate abuses, and the policy underlying the affiliaties entities rule in the NGPA,[449] as raised by Northwest Natural, the Commission notes that Order No.

448. Northwest Natural cites NGPA § 601(b)(1)(E), 15 U.S.C. § 3431(b)(1)(E).

449. *See, generally*, Order No. 269, Tennessee Gas Pipeline Co., 38 FERC ¶ 61,306 (1987).

497 addresses, at least in part, the concerns expressed by the Pennsylvania PUC and New Jersey Natural, and Northwest Natural.[450] Further, it may be appropriate for the Commission to scrutinize carefully transactions where the only competing bidder is an affiliate. However, the Commission is not able to provide specific criteria at this time, and thus, defers this issue for further consideration if a particular concern is raised in the restructuring proceedings.

f. Offers for a Portion of Existing Customer's Capacity

AGD asks the Commission to clarify that the holder of firm transportation service may retain any portion of its certificated service that it wishes to retain, subject to the rules governing the right of first refusal, and have the pipeline's pregranted abandonment authority apply to the remainder of the capacity. AGD states that the final rule makes clear that a prospective shipper may bid against a current firm transportation capacity holder with respect to a portion of the capacity held by the existing holder, but does not address what should be the concomitant right of the firm service holder to bid for the right to retain some amount less than the full amount of the capacity subject to pregranted abandonment.

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450. For example, the standards of conduct (18 CFR 161.3) state, *inter alia*, that a pipeline may not, through a tariff provision or otherwise give its marketing affiliate preference over nonaffiliated customers in matters relating to Part 284 transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority (standard (c)); may not disclose to its affiliate any information the pipeline receives from a nonaffiliated shipper or potential nonaffiliated shipper (standard (e)); and, to the extent it provides to its marketing affiliate information related to transportation of natural gas it must provide that information contemporaneously to all potential shippers, affiliated and nonaffiliated, on its system (standard (f)).

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The request for clarification is granted. The rule is intended to permit the existing capacity holder to elect to retain a portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to the remainder of the service.

The Wisconsin Distributor Group, on the other hand, objects to the provisions that a competing bidder may bid for a portion of the capacity. The Wisconsin Distributor Group states that sellers often offer more favorable rates to purchasers of large quantities for long hauls because of the increased efficiencies associated with these transactions, and that Order No. 636 eliminates the benefits of their economies of scale for large purchasers. The Wisconsin Distributor Group argues that competing bids should be for the same capacity that the existing customer seeks to retain, *i.e.*, the same quantity and the same route. The request for rehearing is denied. As explained in Order No. 636, the policy urged here by the Wisconsin Distributor Group would virtually insulate the very largest holders of capacity from the bidding process.

Natural argues that the Commission erred insofar as the rule provides that the existing shipper need only match a bid for its existing transportation path. Under the rule, Natural argues, an existing shipper could preclude a system haul by creating a bottleneck on the system. Natural states that a short haul should not be allowed to preclude a long haul unless the short haul shipper is paying the same total rate as the long haul. Natural argues that the final rule is an unlawful taking in that it prevents a pipeline from obtaining greater revenue associated with long hauls.

The request for rehearing is denied. The Commission has

answered the Constitutional arguments against this rule. Section 7 of the NGA provides protection against abandonment for current customers that are not in the public interest, and Order No. 636 merely amends Commission procedure for implementing that protection. The policy advocated by Natural would virtually guarantee that the long-haul shipper could take capacity from the current shipper if the current shipper transported the gas for a shorter distance. Natural has confused the bidding process for released capacity under section 284.243 of the regulations with the right of first refusal which is designed to give the existing customer the right to continued service. Under the capacity releasing mechanism, where two new customers are bidding for the same capacity, the regulations require the pipeline to allocate released capacity to the person offering the highest rate no over the maximum tariff rate the pipeline can charge to the releasing shipper. This means that the person seeking to obtain the released capacity can offer up to the pipeline's filed maximum rate for the service received by the releasing shipper, even if the replacement shipper wants the capacity to move gas for a shorter haul.[451] However, under the pregranted abandonment provision, the existing shipper must bid only the maximum rate the pipeline is authorized to charge that shipper.

United Distribution Companies also objects to this provision, arguing that it would permit competitors to fragment the LDCs' needed capacity. As explained above, the procedure guarantees the LDC the right to continued service if it matches the bid of a competing bidder. The capacity will not be fragmented if the LDC exercises its right of first refusal.

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451. Order No. 636 at 30,420-421.

Appendix C

g. Converted Sales

Northwest Natural argues that all converted firm sales service should be protected from pregranted abandonment, including transportation converted outside the stay period. Northwest Natural argues that the rule discriminates against LDCs that converted outside the stay period, and is inconsistent with the decision in *American Gas Association v. FERC.*[452] Northwest Natural argues that the proper result is to treat all converted firm transportation the same, and provide that it will never be subject to pregranted abandonment. United Distribution Companies also argue that the exemption for Order No. 500-J conversions is discriminatory and that the exemption should be expanded to include all existing contracts for long-term transportation service in which the pipeline waived its right to pregranted abandonment. United Distribution Companies assert that where LDCs negotiated for protection against pregranted abandonment, they should be able to retain the benefits of their bargain, and pipelines should be held to their bargains.

The exemption for conversions that took place during the Order No. 500-J stay is based on our decision in Order No. 500-J and the expectations of the parties based on that decision. There is no reason to expand the exemption. The effect of specific contractual provisions or specific contracts that contain a waiver of the right to pregranted abandonment should be examined in the restructuring proceedings, not in this generic proceeding.

Cascade asserts that it is unclear whether Northwest's just approved conversions in Docket No. CP92-79-000 meet the requirements of section 284.221(d)(3). Cascade states that while these conversions were approved May 1, 1992, during the stay

452. 912 F.2d 1496 (D.C. Cir. 1990).

period, they have not yet been completed because their implementation has been tied to actions in other applications. Cascade asks the Commission to clarify that these now approved conversions fall within the section 284.221(d)(3) exemption, or, grant a waiver of the rule for these conversions.

The Order No. 500-J stay applies only to conversions that took place during the period the stay was in effect. The conversions approved in the Northwest proceeding have not yet been implemented and, therefore, the stay does not apply. There is no reason to waive the rule's requirements, and the regulations governing pregranted abandonment will apply to this transportation service on Northwest.

h. Special Circumstances

Kern River argues that the right of first refusal should not apply to any of its customers because at the time those customers executed their service contracts, the Commission's regulations provided for pregranted abandonment. Therefore, Kern River argues, its customers never expected individual abandonment proceedings and know that their service would cease upon contract expiration.

The Commission will not exempt Kern River from the regulations governing the right of first refusal. Kern River should raise this issue in its restructuring proceeding.

4. Storage

AGD and ConEd ask the Commission to clarify that the rules governing pregranted abandonment apply to open access storage arrangements. The rule promulgated by Order No. 636

defines transportation to include storage. Therefore the rules applicable to transportation apply to storage provided under Part 284 as well.

IX. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

A. Adjustment of Purchase Obligations and Firm Capacity

Under section 284.214(d), as promulgated in Order No. 636, firm sales customers may reduce or terminate their rights or obligations to purchase gas by giving notice to the pipeline during the restructuring proceeding.[453] The pipeline is authorized to abandon the sale of gas to the firm customer to the extent the customer exercises such right, or declines to pay the pipeline's restructured sales rate.

Under section 284.214(e), firm shippers must give notice to the pipeline during the restructuring proceeding of whether they want to retain, reduce, or terminate their contractual rights to firm transportation service, and the pipeline must permit reduction or termination of those rights if another shipper bids for the capacity, or may agree to the reduction or termination of such rights in any event. The pipeline is authorized to abandon

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453. Northern Indiana states that it does not understand the Commission's use of the phrase "purchase obligations" in describing LDCs' sales contracts with pipelines, since Order No. 380 and subsequent Commission decisions have eliminated "purchase obligations" under such contracts. Northern Indiana's point is well taken. In the absence of minimum bill provisions, sales customers have rights or entitlements to purchase gas, and obligations to pay demand charges, but no obligations to purchase gas.

service to shippers accordingly. If another shipper is prepared to bid more than the current capacity holder pays for its capacity, the current capacity holder must be willing to match what the competing bidder offers, up to the maximum rate, or release the capacity.

1. Unconditional right to cost-free release of capacity

Pacific Gas and Electric Company (PG&E) asserts that the service and rate changes contemplated by Order No. 636 will almost certainly make some existing transportation contracts far more desirable, while making others wholly unnecessary or far less desirable. PG&E points out that in the Rate Design Policy Statement, the Commission directed parties to address and explore various ways to provide a contract demand adjustment in tandem with increased charges for peak service.[454] However, PG&E argues that the Commission's decision in Order No. 636 to require firm capacity holders to bid to retain constrained capacity, while not providing for unilateral contract reduction rights for unneeded or undesirable capacity, is inequitable and inconsistent with reasoned decision-making.

APGA recognizes that an unrestrained release mechanism during restructuring could cause chaos, but urges the Commission to afford all existing firm capacity holders a unilateral right to turn back some excess capacity during the restructuring proceedings, a maximum of 10,000 MMBtu per day or a modest percentage of current CD, whichever is greater. Customers should be permitted to adjust their demand in response to changes in price that will result from implementing SFV. According to APGA, many small customers have contract

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454. 47 FERC ¶ 61,295 at p. 62,055 (1989).

entitlements in their service agreements that are in excess of their actual current peak day requirements because there are no direct cost consequences of maintaining such levels of entitlements under current rate designs. APGA argues that small customers currently served under a one-part bundled sales rate, under full requirements service, or under two-part schedules with ratcheted demand charges based upon peak deliveries rather than contract entitlements should be authorized to elect an amount of firm transportation capacity during restructuring up to their former contact demand for sales service. APGA argues that pipelines should be at risk to remarket turned-back excess capacity, rather than requiring firm capacity holders to keep and pay for capacity they do not require and for which no other buyer can be found.

As a general matter, pipelines are entitled to recover their legitimate capacity costs, and have designed their rates to do so on the basis of CD levels under their existing firm service contracts. If capacity entitlements are reduced by certain customers and not picked up by others, pipelines will underrecover their capacity costs unless they recover an exit fee from the releasing customer, or until they increase their demand charges under a Section 4 rate filing to reflect the net loss of capacity demand. When they increase their demand charges, capacity costs will be shifted to other firm customers that have not reduced their CD levels. Therefore, the Commission cannot give pipelines' firm customers a unilateral right to reduce or terminate their capacity entitlements during the restructuring proceedings, unless another customer contracts for the released capacity and assumes liability for the costs of the capacity, without shifting costs to the pipeline or other firm customers, or both. No reason has been presented why, during the term of the currently effective contract, these capacity costs should be shifted from the customer who has contracted for the

capacity to the pipeline or other customers that have no need for the capacity.[455]

On the other hand, the Commission in Order No. 636 *requires* all firm customers to evaluate their capacity needs and notify the pipeline during the restructuring proceedings whether they want to retain, reduce, or terminate their current levels of capacity reservation. Furthermore, pipelines are required to permit their firm customers to permanently reassign their capacity to other parties that are willing to pay for it at the restructured rate. Thus, LDCs are afforded unilateral contract reduction rights for unneeded capacity, if they are small customers, or if there are replacement shippers, contrary to PG&E's assertion that they are not. Furthermore, the pipeline and LDC may negotiate a bilateral reduction in capacity even if there is no demand for the capacity from other shippers. But the direction in the Rate Design Policy Statement, and in this proceeding, that parties consider mechanisms for implementing capacity adjustments, does not relieve firm capacity holders from liability for the costs of their capacity reservations under their currently effective contracts (unless the pipeline agrees to such relief) where there is no demand for the capacity by other potential shippers.

Northern Indiana argues that the Commission exceeded its power by mandating that sales customers retain excess transportation capacity. According to Northern Indiana, the Commission in Order No. 636 has abrogated the LDCs' bundled sales contracts, and has no jurisdiction to require LDCs to retain and pay for any minimum quantity of transportation capacity

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455. Pipelines may, however, permit their customers to adjust their contract demands on a seasonal basis as a means of avoiding cost shifts from the implementation of the SFV rate design.

under a service arrangement that is grounded in an abrogated contract. Northern Indiana argues that even if the Commission had the power to rewrite LDC contracts and bind them to something they did not sign, LDCs must have the right to contract and pay for only the transmission capacity they want on each of their pipeline suppliers for there to be any real restructuring and true competition. Furthermore, Northern Indiana argues, customers should not remain bound for years to pay demand charges associated with contracts negotiated prior to the open access era.

The Commission has not abrogated LDCs' bundled sales contracts, contrary to Northern Indiana's assertion. The Commission has required pipelines to provide the sales and transportation under such contracts pursuant to separate certificates of public convenience and necessity, and has required that the point of sale be moved upstream from the city gate. The Commission exercised its authority under Section 5 of the NGA, and its power to fashion remedies, to permit LDCs to reduce or terminate their sales entitlements under existing sales contracts. However, the fact that LDCs have an opportunity to revise their sales entitlements under existing contracts with their pipeline suppliers does not mean they should also have an unqualified right to reduce or terminate their obligations for the costs of transportation capacity under those contracts.

The CPUC seeks clarification that a firm capacity holder may permanently relinquish a portion of its capacity rights without paying an exit fee, if there is demand for the capacity rights, even if the new shipper is not willing to pay the maximum rate for the capacity. CPUC argues that since the original firm capacity holder might not have been willing to pay the pipeline's maximum rates under an SFV rate design, the Commission

should not burden that holder with the full costs of an SFV rate design (*i.e.* through exit fees) simply because others interested in the capacity rights are also unwilling to pay the maximum rates. According to CPUC, a bid at less than the maximum rate reflects what the market is willing to pay for the capacity rights, and permitting a cost-free relinquishment to the bidder who is willing to pay for the capacity would promote the goal of allocative efficiency.[456] Cincinnati Gas argues that existing capacity holders should be permitted to offer a lower rate than the maximum to retain their capacity, even if there are no competing bidders, and to release the capacity cost-free if the pipeline is unwilling to accept the lower rate.

The Commission rejects CPUC's request in order to avoid stranded costs that would have to be absorbed by the pipeline or other customers. However, a pipeline must release an existing capacity holder from its contractual obligations for the capacity if a competing bidder makes an offer for capacity held by the existing firm customer that is equal to or greater than the rate the existing customer is obligated to pay, up to the maximum rate. Of course, the existing capacity holder may offer to pay an exit fee to the pipeline as inducement to release it from those contractual obligations, but that is a matter for negotiation between the parties. Section 284.14(e) provides for automatic abandonment during restructuring when a pipeline agrees to release the existing capacity holder from its contractual obligations, without regard to what inducements are made to the pipeline to secure such agreement. CPUC may be correct

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456. Memphis Light also argues that, during restructuring, LDCs should be able to bid on the capacity they already hold at less than the maximum rate, and if they are the highest bidder, or if there are no other bidders, be entitled to receive service at the rate they bid, even if the pipeline does not agree to a discount.

that a bid for the capacity at less than the maximum rate reflects current market conditions. But the Commission is not implementing non-cost-based pricing for pipelines' transportation capacity in this proceeding. If CPUC's or Cincinnati Gas's proposed clarifications were adopted, a portion of the costs of the capacity in question would be shifted from the customer that contracted for the capacity to the pipeline or other customers that have no need for it.

Transco also seeks clarification of the same point, but to the opposite effect, namely that an existing holder of firm capacity is not fully relieved of its contractual obligations unless a third party bidder agrees to pay the maximum rate for the capacity to be relinquished. Clarification along these lines, Transco argues, would be consistent with the policy under the temporary capacity release program of the new section 284.243, where the original capacity holder remains liable for the applicable rate for released capacity, even though the replacement shipper pays a lesser rate. El Paso seeks clarification that an existing shipper may not release, and be released from liability for, *all* of its capacity under its current contract when there is a bid for only a *portion* of it.

Except to the extent pipelines are "at risk" for unsubscribed firm capacity, they are entitled to seek to recover their capacity costs through a fully allocated cost-based rate. However, a pipeline may have contracted to provide firm service for less than the maximum rate. For the reasons discussed above, a pipeline would underrecover its capacity costs if existing firm capacity holders were fully relieved of their liability under currently effective capacity reservations where a replacement shipper agrees to purchase that capacity at less than the rate the current shipper is obligated to pay. If another creditworthy shipper offers to pay a rate that is equal to or greater than the

existing capacity holder's rate, up to the maximum rate, for a part of the capacity that an existing capacity holder seeks to release, the pipeline must release the existing capacity holder from its contractual obligations for the capacity sought by the other. But the pipeline is not required to release the existing capacity holder from liability for capacity for which another bidder offers less than the rate the existing capacity holder is obligated to pay. The pipeline is no worse off when the substitute shipper pays the same rate the releasing shipper is paying, even though that rate is less than the maximum rate.

2. Pipeline opportunity to adjust contracts for capacity

ANR requests the Commission to clarify that not only shippers, but also pipelines, have opportunities to adjust certain contractual commitments during restructuring. ANR asserts that a contract for firm capacity at a substantial discount, entered into when capacity release rights were not available, could become substantially more valuable after implementation of Order No. 636. Unless it is allowed to make adjustments to the contract, ANR asserts that the current shipper may release the discounted transportation to another shipper in different competitive circumstances that might not warrant the discount.

Even if an existing capacity holder's contract for transportation at a discount becomes more valuable because of the capacity release program, the pipeline's ability to increase the rates for the service will depend on whether its contract affords it a right to renegotiate or eliminate the discount. If there is demand for the capacity at higher rates, and the existing capacity holder's discount is not contractually guaranteed, the existing capacity holder will have to match the competing bids, up to the maximum rate, or release the capacity.

3. Reduction or termination of transportation capacity embedded in bundled sales service

SoCal Edison requests the Commission to clarify that the CD levels of transportation capacity embedded in a bundled sales service can only be reduced or terminated during restructuring under the same conditions that capacity may be released by existing transportation customers. SoCal Edison is correct, and the clarification is accordingly granted. Under Order No. 636, the capacity rights of bundled sales customers are converted into unbundled firm transportation rights. At that point, the sales customers are to be treated no differently from other firm transportation customers.

4. Right of first refusal during restructuring proceedings

Citizens Gas apparently interprets Order No. 636 to provide that existing firm capacity holders are subject to losing their capacity during the restructuring proceedings unless they exercise a "right of first refusal" by agreeing to match any greater rate up to the maximum rate, and the most favorable contract term offered by any other person seeking the capacity.[457] Citizens Gas seeks rehearing of this provision on various grounds. Citizens Gas is mistaken about what Order No. 636 provides. An existing firm capacity holder may have to match a competing rate bid for its capacity during restructuring if it is receiving transportation at a discount, and does not have a contract that guarantees it that discount, but it does not have to match any other term of competing offers to retain its capacity. The final rule differs from the proposal in the NOPR in this respect. Furthermore, the requirements for retaining firm capacity under

457. Cincinnati Gas seeks clarification of this same issue.

currently effective contracts during restructuring proceedings are different from those for retaining firm capacity, *i.e.* by exercising a right of first refusal, when a contract has expired.

5. Permitting immediate reduction or termination of customers' sales entitlements

Marathon seeks rehearing of the Commission's decision in Order No. 636 to permit immediate reduction or termination of pipeline customers' sales entitlements, arguing that it will create significant dislocation and confusion in the natural gas industry. Marathon submits that economic dislocation and the transition costs involved in restructuring long-term supply agreements could be minimized by allowing existing pipeline gas sales contracts to run their course, and suggests the Decontrol Act as a model for an orderly transition. Under that Act, deregulation is phased in as contracts expire or are terminated, and parties may expressly agree to deregulated prices in continuing contracts.

The Commission indicated in Order No. 636 that sales customers may choose not to exercise their right to reduce or terminate their sales entitlements during restructuring to its fullest extent, in order to avoid or minimize transition costs. The Commission's decision allows sales customers the choice of whether to continue their sales contracts with their pipeline suppliers or arrange for other suppliers and bear the consequences of making that choice. At the same time, pipelines are permitted to sell their gas at market-sensitive prices, thus enabling them to offer more competitive rates to retain their sales customers. Marathon is the only party that raises this issue on rehearing. The industry as a whole seems to accept the Commission's judgment that affording pipeline sales customers a right to reduce or terminate their sales entitlements during

restructuring is an appropriate remedy for their previous inability to secure reliable service any other way because of the lack of high quality firm transportation. Marathon's request for rehearing on this issue is denied.

6. Revisions to 18 C.F.R. § 284.14(e)

Section 284.14(e)(4) provides that a downstream pipeline may not terminate its capacity rights on an upstream pipeline during restructuring proceedings. National Fuel requests that a downstream pipeline be permitted to pursue capacity reductions on upstream pipelines during the restructuring proceedings if it first gives notice to its historical sales customers and receives no objections that it cannot resolve. According to National Fuel, the lack of opportunity to reduce unneeded capacity will disadvantage downstream pipelines and their customers, where neither has any need for excess capacity on the upstream pipeline. National Fuel also seeks clarification that the prohibition against downstream pipelines releasing upstream capacity during restructuring does not preclude downstream pipelines from converting from sales to transportation on the upstream pipeline during restructuring proceedings.

The Commission will grant National Fuel's request and revise the regulatory text accordingly, to permit a downstream pipeline to pursue capacity reductions on upstream pipelines with the consent of the potentially affected customers of the downstream pipeline. As discussed above, the downstream pipeline's ability to reduce its capacity on upstream pipelines will depend on the willingness of other parties to contract for the upstream capacity or the willingness of the upstream pipeline to agree to a reduction in the absence of another buyer.

Appendix C

The Commission is also revising certain other provisions of section 284.14(e), to conform it to the provisions of the preamble of Order No. 636. Specifically, paragraph (e)(2) is revised to provide firm shippers an explicit right to reduce or terminate their firm service rights and obligations where the pipeline receives an offer for the capacity during the restructuring proceeding from a creditworthy shipper that is equal to or greater than the rate the existing shipper is obligated to pay, up to the maximum rate, or the pipeline otherwise agrees to a reduction or termination. Furthermore, paragraph (e)(3) is revised to permit the pipeline to abandon service to a firm shipper if, during the restructuring proceeding, another shipper offers a higher rate, up to the maximum rate, which the existing shipper (who is not contractually entitled to a discount) declines to match.

B. Transition Costs and Recovery Mechanisms

The Commission recognized in Order No. 636 that pipelines may incur certain transition costs as a direct result of implementing the requirements of that order. The order envisioned four kinds of such costs: unrecovered gas costs in a pipeline's Account No. 191, to be recovered by means of a "direct bill" to its former, bundled firm sales customers; gas supply realignment (GSR) costs that result from a pipeline having to reform or terminate existing supply contracts in response to customer decisions during the restructuring proceedings, to be recovered from Part 284 firm transportation customers by means of a reservation fee surcharge or a negotiated exit fee; costs that are now incurred in connection with bundled sales service that cannot be directly assigned to customers of unbundled services, called "stranded costs," to be included for recovery in a general rate case under section 4 of the NGA; and the costs of new facilities to physically implement

Order No. 636, also to be included for recovery in a general rate case.

About 70 of the requests for rehearing raise issues concerning recovery of transition costs. The requests present a wide range of objections, requests for clarification, and counterproposals to the transition cost provisions of Order No. 636. The major issue is raised by the state commissions, consumer advocates, and LDCs — a charge that the 100 percent passthrough of pipelines' gas supply realignment (GSR) costs through a demand surcharge overburdens the captive customers of LDCs with the costs of restructuring while allotting none of those costs to pipelines, industrial consumers, producers, and marketers — even though the latter groups reap virtually all of the benefits. The Commission has decided on rehearing to respond to this concern by requiring pipelines to recover 10 percent of their GSR costs through their rates for interruptible transportation under their Part 284 blanket certificate.

1. Equitable allocation of GSR costs

a. Proposals to shift costs to other parties

The New York PSC objects to pipelines being allowed to recover 100 percent of their transition costs, arguing they will thus have little or no incentive to minimize such costs. The New York PSC would have the Commission require a sharing of transition cost responsibility between the pipeline and its customers under the guidelines of Order No. 528 or, at a minimum, require pipelines to absorb 10 percent of those costs. The New York PSC would have the remaining unabsorbed costs spread over a broader industry base by requiring an appropriate percentage or fixed unit amount of transition costs to be

recovered on the basis of total throughput. The New York PSC argues that recovering the transition costs through the commodity surcharge would provide pipelines implementing an SFV rate design with an incentive to maximize throughput while more permanent incentive rate mechanisms are under consideration, and significantly mitigate the increased burden being placed on residential consumers by Order No. 636.

Citizen Action argues that the Commission erred in failing to ascertain or even estimate the amount of transition costs that may be incurred as a result of Order No. 636, especially the GSR costs.[458] Citizen Action maintains that transition costs under the rule could range between $2 and $6 billion, and argues that the Commission erred in permitting pipelines to recover 100 percent of their GSR costs. According to Citizen Action, these costs ought to be the sole responsibility of producers and pipelines, not pipeline customers and consumers. Citizen Action urges the Commission to use authority under Section 5(a) of the NGA to abrogate all contracts between pipelines and producers that contain onerous take-or-pay provisions, or prices that exceed market levels, or, alternatively, to prohibit any pipeline passthrough of transition costs associated with reforming such contracts. Citizen Action also would not limit recovery of GSR costs to firm Part 284 transportation customers, but would spread such costs over a wider customer base.

Illinois Power thinks that by permitting pipelines to recover 100 percent of eligible, prudently incurred transition costs through a demand charge, producers will likely insist on recovering 100 cents on the dollar. It recommends that the

458. Alabama Gas and Illinois Power also argue that the Commission erred by not assessing the magnitude of the transition costs and considering whether they were outweighed by the competitive benefits.

Commission use its authority under Section 7 of the NGA to establish a conditioning mechanism under which a pipeline found to be in compliance with Order No. 636 may deny a producer the benefits of open-access transportation, unless the producer agrees to release the pipeline from gas supply contracts for which the pipeline no longer has a market because of Order No. 636. According to Illinois Power, the Commission justifies abrogation of the pipeline sales contracts on the ground that they were entered into during a period when there was not adequate competition. The same holds true, it argues, for the above-market producer contracts. They contend that their proposal is merely a variant on the take-or-pay crediting mechanism instituted under Order No. 500, which the court upheld in *American Gas Association v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990), and that the crediting mechanism did not keep gas from flowing between willing sellers and willing buyers — the only reason stated in Order No. 636 for not adopting such a proposal.

Various commenters on the NOPR submitted estimates of transition costs that might arise from implementation of the final rule. The Commission did not find it necessary to make its own estimate, because most of the costs at issue are costs that pipelines had already incurred or were obligated to incur, and would have been entitled to recover regardless of restructuring. Furthermore, as discussed below, the Commission believes that the costs of realigning contracts should approximately equal the benefits of the realignment.

While many of the LDCs, state commissions, and consumer advocates suggest various regulatory devices for shifting a substantial portion of the GSR costs away from the customers for whom the gas supply was secured and the customers that

will receive the benefit of improved open access transportation service, no one presents any good reason for doing so. They generally allege that since Order No. 636 will benefit all segments of the gas industry, all segments should bear the costs. The Commission believes that the benefits of Order No. 636 indeed will be widespread. Furthermore, the costs of restructuring will be borne in one way or another by all that participate. But the question here is, who should bear the specific category of gas supply realignment costs?

All of these requests are based on two premises: 1) that Order No. 636 will give rise to potentially enormous GSR costs that would not have been incurred but for Order No. 636, and 2) that it is unfair to require recovery of these costs exclusively from the firm customers for whom the pipelines originally contracted to purchase the gas supplies, and those who will avail themselves of the upgraded, open access transportation services. The Commission does not accept either of these premises.

The 100 percent recovery policy of Order No. 636 provides that, upon full compliance with the rule, pipelines will be entitled to recover their prudently incurred GSR costs necessary to reform gas supply contracts in response to customer purchasing decisions during restructuring. The Commission does not accept the premise that the cost of gas under a contract reformed to reflect current demand, together with the costs of reforming that contract, will necessarily exceed the long-term cost of gas under the same contract if it were not reformed.

While pipelines may make lump sum payments to reform such contracts, and such costs will be labeled "Order No. 636 transition costs," the pipelines will presumably receive more favorable prices or other valuable consideration resulting from

contract reformation. If the Commission had not issued Order No. 636, and the contracts in question were not reformed, the pipeline would likely have had to pay the higher prices or be subject to the less favorable contract terms, and, assuming the costs were not excessive due to fraud, abuse, or similar grounds, the pipeline (under a pre-Order No. 636 regime) would be legally entitled to recover the prudently incurred costs of such contracts from its customers. Thus, the pipeline's sales customers and former sales customers that will share the costs of realigning gas supply contracts will also stand to benefit from the realignment of those contracts. Based upon the Commission's substantial experience to date, reformed contracts are considerably more market responsive. Even if the pipeline's former sales customers choose to reduce or terminate their sales entitlements under existing contracts and purchase gas supplies from nonpipeline merchants, the more favorable terms under the pipeline's realigned contracts will benefit them indirectly by affecting the prices that competing merchants can charge.[459]

Order No. 636 does not ask producers to forego the benefits of their gas sales contracts that were entered into on terms that were presumably reasonable at the time. Generally, the Commission has no jurisdiction over the prices or terms of pipelines' contracts with producers.[460] The Commission in Order No. 636 does not seek to deprive pipelines of a reasonable

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459. Customers that have never been sales customers of the pipeline may also benefit from the availability of the pipeline's portfolio of realigned gas contracts, either by purchasing gas from the pipeline, or as a result of the effect of the prices offered by the pipeline on prices of competing merchants.

460. The Commission's jurisdiction over most producer/pipeline supply contracts has already been removed under the NGPA. As of January 1, 1993, there will be no remaining vestiges of such jurisdiction by virtue of the Decontrol Act.

opportunity to recover the costs of realigning their gas supply contracts under which full recovery of gas costs was guaranteed by Section 601(c) of the NGPA and the Commission's PGA regulations. None of the requests for rehearing is persuasive that such steps should be taken.[461] For one thing, pipelines have already absorbed a substantial amount of take-or-pay and realignment cost under Order Nos. 500 and 528. The Commission's records indicate that as of June 30, 1992, pipelines have made filings under those orders concerning nearly $10 billion, and have agreed to absorb nearly $ 3.6 billion of such costs (36.6 percent), and sought to passthrough the balance of nearly $ 6.4 billion (63.4 percent) to consumers. Of the amount to be passed through, approximately $3.5 billion has been directly billed (55.5 percent), and approximately $2.8 billion (44.5 percent) has been billed through a volumetric surcharge. However, the Commission will require pipelines to recover 10 percent of their prudently incurred GSR costs through their interruptible transportation rates under their Part 284 blanket certificate, as described below, thus further spreading some of those costs to the pipeline's interruptible sales and transportation customers, as discussed below.

b. Contract assignments and prudence reviews

The Wisconsin Distributor Group asserts that if the Commission ever hopes to get Order No. 636 off the ground, it must develop incentives to minimize transition costs. The

461. Accordingly, the Commission will not respond to each specific proposal for mechanisms to shift GSR costs to producers or pipelines — such as conditioning producer access to open access transportation on making concessions in contract reformation, or requiring pipeline absorption of some percentage of those costs — because the arguments for shifting the costs are not persuasive.

Wisconsin Distributors contend that, absent some improvement in Order No. 636's treatment of transition costs, many LDCs will be pushed back to pipelines (because they cannot afford to leave) rather than to a competitive marketplace. The Wisconsin Distributor Group also argues that prudence review will not be a meaningful remedy. They assert that prudence cases are very difficult, complex, expensive, and time-consuming, and the party whose actions are in question controls all the documents. Furthermore, they assert that the Commission has not generally pursued allegations of improper pipeline purchasing practices with vigor.

Nor does the Wisconsin Distributor Group find solace in contract assignments as a remedy to mitigate transition costs, because in most instances, they assert, the purchaser would take over a non-market responsive gas contract. In that event, they conclude, the purchaser's gas costs would increase or remain high, and the purchaser would be precluded from meaningful access to competitive gas markets for the life of the assigned contracts. The Wisconsin Distributor Group urges the Commission to afford pipelines and their customers far greater latitude to negotiate GSR cost recovery mechanisms that will provide effective incentives to producers and pipelines to minimize those costs.

The NASUCA also questions the potential for pipelines to mitigate GSR costs by making assignments of their unneeded gas supply contracts to their customers. NASUCA asserts that a pipeline will have no need to jettison its gas supply contracts with competitive, market-based prices — only their non-market responsive contracts. Thus, they argue, captive LDCs may be presented with a Hobson's choice: either pay for non-market responsive contracts through transition costs or pay for them

through contract assignment. NASUCA suggests that the Commission require pipelines to adjust their prices under contracts they seek to directly assign to their customers in order to reflect market-based prices (with any necessary adjustment to reflect the long-term firm nature of the contract) by exercising their rights under any "FERC out" or "government out" clauses. According to NASUCA, Order No. 636 creates a situation for pipelines that makes it financially impossible for them to perform under existing contracts because the Commission has permitted the abrogation of the pipeline/customer sales contracts that initially supported the producer contracts. Therefore, they argue, pipelines' diligence in asserting their rights under any such "FERC out" or "government out" clauses should be a standard for establishing their prudence in incurring any GSR costs.

A pipeline's Part 284 transportation customers, including formerly, bundled firm sales customers, will be presented with various choices for arranging for gas supply and enhanced transportation options when the pipeline implements Order No. 636. The Wisconsin Distributor Group and NASUCA correctly point out that none of the choices avoids the prudently incurred costs of gas supply under the pipeline's existing portfolio of contracts. But, the Commission is attempting to provide pipelines and their customers with equitable means to effectuate a transition, not some device for avoiding existing contracts with no reasonable provision for compensation. Pipelines and producers are encouraged to offer assignments of their unneeded gas supply contracts, and if they do, are required to make such offers on a nondiscriminatory basis. But a pipeline's customers are not required to accept such assignments if they conclude that other means of paying the pipeline's GSR costs are more advantageous.

Prudence reviews are intended to provide a meaningful

remedy for imprudence, not to force absorption of costs by pipelines for decisions that were prudent under the circumstances. The Commission's past review of prudence challenges is criticized because the Commission has failed to find imprudence in circumstances where the record did not warrant such a finding. But the Commission's responsibility is to find imprudence only when it is shown. Given the importance of prudence challenges in the future, the Commission will consider prudence challenges in a timely and vigorous manner. Simply put, the Commission will carefully examine prudence challenges in proceedings to recover Order No. 636 transition costs to ensure that those costs have been minimized.

If pipelines have rights under their producer supply contracts to adjust the price or terms of those contracts, of course they should exercise those rights for the benefit of their customers. A failure to do so would clearly be imprudent. However, the Commission cannot construe what the contractual rights of parties may be under contract clauses that are not before us, and indeed, the Commission's jurisdiction to construe contracts between pipelines and producers is quite narrow.

c. Shifting costs to producers

According to the NASUCA, the Commission has authority under Section 5 of the NGA to abrogate the non-market responsive contracts between pipelines and producers, and should place producers with jurisdictional contracts on notice that any failure to renegotiate such contracts in good faith could result in abrogation. The Commission's decision not to exercise Section 5 abrogation authority in Order Nos. 500-H and 500-I is not dispositive, they argue. Under those orders, the parties sought to circumvent the take-or-pay clauses of producer/

pipeline contracts with claims that competitive conditions made compliance with the take-or-pay provisions difficult. However, according to NASUCA, economic and competitive trends in the industry do not form the basis for invoking Section 5 authority against producer contracts in restructuring proceedings. Rather, they argue, the Commission's use of that authority to abrogate contracts between pipelines and their customers mandates equal treatment on the pipelines' supply side.

The Tennessee and Columbia Small Customers argue that a producer's access to additional firm transportation and storage capacity that becomes available as a result of restructuring should be linked with the reformation of the producer's existing gas supply contracts. This linkage is justified, according to these customer groups, because the producers will be enabled to compete in markets from which they are currently excluded as a result of the pipelines' competitive advantages. Furthermore, they assert, implementation of the SFV rate design is likely to increase producer netback prices by shifting costs out of the pipelines' usage charges.

These small customer groups also say that producers will not accept settlements that approach the level of discounts they reportedly agreed to in connection with take-or-pay contract settlements under Order Nos. 500 and 528, because the uncertainties and risks surrounding the enforcement of gas sales contracts at the time of those negotiations no longer exist. Producers may even be able to extract premiums for contract reformation, they argue, because the timetable adopted for compliance with Order No. 636 will severely disadvantage pipelines in negotiating buydowns and buyouts, and may force them to offer "sweeteners" even to renegotiate market-clearing contracts.

Appendix C

In Order No. 636, the Commission stated that pipelines must take all possible steps to minimize transition costs in the course of realigning their gas supply contracts. Many of the LDCs, state commissions, and consumer advocates (and even one pipeline[462]) urge the Commission to afford pipelines additional commercial leverage in these negotiations to extract concessions from producers. Their unstated premise is that if prices under existing, valid, long-term gas supply contracts are higher than current market prices, producers should have to relinquish some part of their benefits under those contracts as a remedy.

If a pipeline entered into an existing gas supply contract in a prudent fashion, even though prices and terms in the market are now more favorable, the Commission strongly urges the pipeline and its supplier to aim for a fair adjustment of the terms of the contract to bring it into line with current and future market conditions. Moreover, as the Commission stated in Order No. 636, the added presumption of prudence afforded to costs filed for recovery under Order Nos. 500 and 528 does not apply to GSR costs.[463] Thus, pipelines have an incentive to renegotiate to minimize costs. And if past practices are a future indicator, producers will recognize that they may not receive the full benefit of a reformation bargain if part of the pipeline's costs are later judged to be imprudent.

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462. Tenneco proposes, *inter alia*, that in order to provide an incentive to producers to make concessions in the renegotiation of uneconomic contracts, pipelines should be permitted to collect an additional demand or commodity charge for transportation of gas purchased from producers that have refused to renegotiate such contracts. The Commission has repeatedly rejected such conditioned access in the past and will do so here.

463. "[T]he policies of Order Nos 500 and 528 . . . will generally not be applicable to recovery of gas supply realignment costs attributable to this rule . . . ." "[Pipelines] will not be afforded protection from challenges to their prudence in this matter." Order No. 636 at p. 30,460.

Appendix C

d. Spreading costs to interruptible and 7(c) shippers

The Iowa, Missouri and Wisconsin Commissions question the wisdom of allowing GSR costs to be recovered through a reservation fee surcharge or exit fee, neither of which will be applicable to interruptible transportation service or transportation under individual NGA Section 7(c) certificates. They assert that historic sales customers that might elect to leave the system to pursue a least-cost purchasing strategy will be discouraged from doing so if pipelines are permitted to impose exit fees. A customer leaving one system to purchase gas on another will have to pay an exit fee on the first and reservation charge on the second. They also argue that permitting a pipeline to recover its GSR costs primarily from one group of customers, the LDCs that historically were resellers, will handicap those customers in competing with the pipeline as merchant, independent marketers, and producers — who do not bear these costs — in the competition for sales to prime, high-load factor users. The Iowa, Missouri, and Wisconsin commissions conclude that the solution is obvious: spread transition costs among the full universe of users of the pipeline's services on a strict volumetric basis.

The CPUC also argues that there is no reason why the pipelines' interruptible transportation customers should not have to pay a part of the transition costs, and that excusing them from these costs is a radical and arbitrary departure from the policies of Order No. 528. Furthermore, the CPUC asserts, by singling out firm transportation customers to pay the transition costs, the Commission has encouraged many customers to become interruptible transportation customers, rather than participate in the firm capacity reallocation programs, thus further concentrating the burden of these costs on firm transportation

customers such as LDCs. Like the other state commissions, the CPUC also recommends a volumetric surcharge on transportation service as the mechanism for recovery of GSR costs, asserting that on many pipelines, the amounts of volumetric surcharges under Order Nos. 500 and 528 have diminished to insignificant levels (4¢/dth for El Paso, 1¢/dth for Transwestern), and arguing that additional surcharges would not jeopardize producers' revenues and production.

The National Association of Gas Consumers asserts that GSR costs will be caused by decreases in the volume of gas purchased, not the peak demands. Therefore, high load factor customers will cause more gas supply realignment costs per unit of demand, but will pay the same charge per unit of demand. The National Association of Gas Consumers argues that this situation should be remedied by including any allowed transition costs in the transportation commodity charge.

The Commission generally follows the principle that assessment of costs should reflect cost causation principles. The prescribed surcharge on reservation fees for firm transportation under a pipeline's Part 284 blanket certificate is an appropriate means of recovering the bulk of GSR costs, because such a surcharge spreads the costs over a broad group of the pipeline's customers that will benefit from the improved quality of transportation mandated by the final rule. The Commission also recognizes that to effectuate an equitable transition to a more competitive market, it is necessary to allow short-term assessments to be spread over a broader customer base. On rehearing, therefore, the Commission has decided to require pipelines to recover 10 percent of their prudently incurred GSR costs through their interruptible transportation rate for interruptible service under their Part 284 blanket certificates. Pipelines must therefore allocate 10 percent of their GSR costs

to their interruptible service to be recovered in their interruptible rates, not in the form of a surcharge, but as a cost allocated to that service. Furthermore, in order to avoid double charging interruptible transportation customers, pipelines must exclude the GSR surcharges on the firm reservation fee in calculating the amount of fixed costs to be recovered through interruptible rates, as in, for example, the derivation of an interruptible rate from the firm reservation fee. This modification of the recovery mechanism for GSR costs will permit collection of a part of the GSR costs from the pipelines' open access interruptible customers — customers that would not have been subject to assessment of any such costs under the final rule.

The Commission recognizes that the uncertainties surrounding any estimates of interruptible throughput after restructuring may make it difficult to design interruptible rates that will assure pipeline recovery of the GSR costs. But the Commission does not intend for pipelines to have to absorb the portion of GSR costs assigned to interruptible transportation, and encourages the pipelines and the parties to the restructuring to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover (but not overrecover) those costs.

Assessing 10 percent of the transition costs to interruptible rates will be short term, not a permanent feature of pipelines' rates, and constitute a pragmatic adjustment to Order No. 636. The Commission finds this to be a reasonable transitional trade-off in light of the rule's long-term benefits.

2. What constitutes gas supply realignment costs?

The Illinois Commerce Commission requests clarification

of what constitutes a pipeline's GSR costs, whether this cost is the difference between the cost of gas under the pipeline's existing portfolio and the cost of a portfolio of gas with similar volumes and durations if purchased today — *i.e.*, the amount by which the portfolio is above market — or the cost of buying out all of the pipeline's above-market contracts. If the latter view is taken, the Illinois Commerce Commission asserts that pipelines will be able to reap a windfall by divesting themselves of all above-market contracts, billing their customers for those buy-outs, and marketing the gas under their remaining contracts (with prices at or below market) at market-based prices. The Northern Distributor Group argues that a pipeline's costs of realigning its above-market contracts should be offset against the capitalized or present value of the below-market contracts it retains or assigns to an affiliate.

The Iowa, Missouri, and Wisconsin Commissions question whether a pipeline will be able to "cherry-pick" among its most favorable supply contracts and pass through the costs of selective buyouts of its most onerous above-market contracts. If so, the state commissions assert, capacity users will bear the costs of the contracts that the pipeline's management elects to shed, and the pipeline, as a marketer, will be free to market a choice mix of gas under the better of its contractual arrangements. Philadelphia Electric suggests that a substantial portion of the GSR costs should be recoverable through a volumetric surcharge to prevent pipelines from reforming their portfolio of supply contracts to below market prices and passing all of the costs of such reformations through as demand surcharges.

Pipelines may not use the reservation fee surcharge to recover GSR costs as a tool for reducing their gas supply portfolios to below-market price levels. There may be disputes about how much cost a pipeline may prudently incur to realign

its supply portfolio, and to what extent its retained portfolio of contracts should serve to reduce its claims for GSR costs. The Commission will consider these concerns on a case-by-case basis as they arise. In the meanwhile, pipelines must act with prudence, good faith, and due regard to their customers' best interests in this matter.

The Iowa, Missouri, and Wisconsin Commissions also suggest that Order No. 636 failed to establish a "bright line" between GSR costs and take-or-pay costs recoverable (with partial pipeline absorption) under the guidelines of Order No. 528.[464] They argue that the ambiguities of the Commission's discussion of this distinction invite extreme positions and posturing in individual cases, as pipelines seek to recover everything but the kitchen sink under Order No. 636, and customers seek to exclude virtually everything. Tenneco asks for clarification that the costs of realigning gas supply contracts incurred after the issuance of Order No. 636, but before the Commission's approval of the pipeline's compliance filing will qualify for 100 percent recovery.

According to the Kentucky PSC, the Commission properly recognized that pipeline actions to restructure their out-of-line gas purchase contacts to reflect market conditions are not, or should not have been, a new activity, and can by no means be attributed solely to the restructuring requirements of Order No. 636. The Kentucky PSC urges the Commission to make clear that costs and liabilities related to service provided prior to the effective date of restructuring cannot qualify as Order No. 636 transition costs.

The CPUC argues that the eligibility standard for recovery

464. Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 53 FERC ¶ 61,163 (1990).

of GSR costs under Order No. 636 is virtually meaningless, because no basis was provided for distinguishing GSR costs resulting from Order No. 636 from costs that arise independently of that order. The CPUC asserts that PGT has never filed with the Federal Energy Regulatory Commission to recover take-or-pay settlement costs under the equitable sharing mechanism, but is presently faced with numerous take-or-pay types of lawsuits and claims. Moreover, CPUC argues that pipelines such as PGT still have take-or-pay exposure because they have not been diligent during the past ten years in reforming contracts and shedding gas supplies, and is concerned that Order No. 636 will provide an opportunity for such pipelines to evade the equitable sharing mechanism.

Maryland People's Counsel is also concerned that the greatest GSR costs will be incurred by pipelines that have been the most recalcitrant or reluctant in restructuring their supply contracts under Order Nos. 500 and 528. Therefore, the customers who have suffered the financial consequences of their earlier lack of access to competitively priced markets, and their pipeline suppliers' reluctance to allow conversion to transportation, will now bear the full financial brunt of mandatory restructuring and the 100 percent passthrough of their pipelines GSR costs. Maryland People's Counsel concludes it would be grossly unfair to assure 100 percent passthrough of take-or-pay buyout and buydown costs to pipelines that previously failed to take the necessary steps to reform their contracts.

Tejas urges the Commission to clarify that pipelines were obligated to buy down their gas portfolios to a competitive market responsive level under Order No. 436, and to flow those transition costs through under Order No. 528, and that only those additional costs incurred by pipelines to reduce the size of their

market responsive portfolios to adjust to a smaller unbundled sales market should be defined as properly recoverable under Order No. 636.

Obviously there are some similarities between take-or-pay settlement costs and GSR costs. On the other hand, there are important differences that now warrant the different policies on absorption. Order No. 436 provided strong incentives to, but did not compel, pipelines to offer open access transportation service, which led in turn to increased take-or-pay liabilities. Under Order Nos. 500 and 528, pipelines were encouraged, although not compelled, to absorb some of the costs of entering into contracts that gave rise to that liability. The policies of Order Nos. 500 and 528 were designed to fairly apportion the substantial portion of buyout and buydown costs without attempting to ascribe blame to any one segment of the industry.

Now, Order No. 636 requires pipelines to restructure their services to afford all consumers with opportunities to fully realize the benefits of a competitive market in natural gas. Pipelines have no choice, however, but to implement the restructuring required under Order No. 636. Pipelines must realign their existing portfolio of gas supply contracts to adjust to their customers' purchasing decisions and to greater competition from other merchants. Order No. 636 requires pipelines to restructure their services and operations to avail their competitors unprecedented access to the pipelines' historic sales customers, and permits those sales customers the choice of reducing their obligations under their existing sales contract. In these circumstances, it is not equitable to require pipelines to absorb further the costs that result from those requirements.

Guidelines and policies will be developed to distinguish precisely between Order No. 528 costs and the costs attributable

to Order No. 636 costs as the Commission addresses disputes in concrete cases.[465] There may be circumstances that militate against 100 percent recovery of the costs of a contract reformation under Order No. 636, and, as the Commission said in Order No. 636, where the total sum of GSR costs is partially eligible and partially ineligible for 100 percent recovery, the parties should devise an appropriate allocation among the two recovery mechanisms.

Moreover, the Commission will clarify that the use of a surcharge on transportation rates to recover GSR costs will be limited to such costs that arise as a result of customers' decisions as a result of the restructuring proceedings. If sales customers reduce or terminate their sales entitlements upon expiration of their contract terms after restructuring, and the pipeline finds it necessary to further realign supply contracts, the costs of such realignments will not be recoverable through Order No. 636 surcharges on transportation rates, but only through market-based sales rates. Thus, after restructuring is complete, the pipeline should seek to address any future realignment costs in the gas supply agreement with its gas purchasers.

Some parties request that the Commission provide an option for pipelines to voluntarily absorb some portion of their GSR costs to avoid prudence challenges. Nothing in Order No. 636 precludes the pipeline from doing this on a voluntary basis, and the Commission encourages all parties to be flexible in dealing with transition cost recovery issues.[466]

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465. *See, e.g.*, Florida Gas Transmission Company, 59 FERC ¶ 61,413 (1992)(gas supply realignment costs incurred in December 1991 and January 1992 not eligible for recovery under Order No. 636 recovery mechanisms).

466. Any costs that would qualify for recovery as GSR costs could be (Cont'd)

3. Exemptions from demand surcharge on firm transportation

NGSA requests rehearing of the decision to have surcharges for GSR costs imposed on the reservation fees for *all* transportation under a pipeline's Part 284 blanket certificate. NGSA notes that transportation rates for service under individual Section 7(c) certificates are not subject to the surcharge, presumably because the provision of such services is unrelated to any gas supply realignment costs. However, NGSA argues that firm transportation service under Part 284 that commences after a pipeline completes restructuring, and is unrelated to service conversions by the pipeline's sales customers should also be exempt from GSR cost surcharges.[467] According to NGSA, to impose surcharges on such service departs from the principle that cost responsibility should follow cost causation.

The Virginia Electric Power Company (VEPCO) argues that the firm transportation service it receives from Columbia Gas Transmission Corporation under Columbia's Part 284 certificate should be exempt from the surcharge for GSR costs because VEPCO was never a sales customer of Columbia, and the facilities used to provide the service were constructed, with an

(Cont'd)

filed for recovery under Order No. 528. Since challenges to a pipeline's prudence in the incurrence of take-or-pay costs are generally avoided when they file for recovery under Order No. 528, pipelines continue to have, at their election, this option.

467. American Paper Institute argues that GSR costs are attributable solely to those currently being served by the pipelines' merchant function, and the responsibility for such costs should rest solely with those existing sales customers. See also, Florida Power and Light Company's (Florida Power) request for rehearing.

contribution in aide of construction from VEPCO, pursuant to a case-specific Section 7(c) certificate. Therefore, VEPCO argues, its service did not displace pipeline sales, and it was not the beneficiary of capacity made available as a part of Columbia's transition from merchant to transporter. Both NGSA and VEPCO point out that many of the firm transportation transactions initiated in the past few years under Part 284 blanket certificates are identical in all respects with firm transportation initiated earlier under individual Section 7(c) certificates, and argue that they would have been certificated under individual certificates but for the Commission's policy against granting such certificates to pipelines that hold Part 284 blanket certificates.

On the other hand, Philadelphia Electric seeks rehearing of the decision to exempt long-haul market-area Section 7(c) transportation from any transition cost responsibility. Philadelphia Electric asserts that shippers under individual Section 7(c) certificates will reap the same benefits under Order No. 636 as shippers under Part 284. Philadelphia Electric asserts that the Commission has consistently required a contribution to take-or-pay costs by individual Section 7(c) shippers,[468] and storage customers,[469] and argues that the apparent departure in Order No. 636 from established Commission policy favoring the broadest distribution of such costs among similarly situated customers is unexplained and arbitrary.

The Commission recognizes that any prospective allocation of GSR costs will depart somewhat from traditional cost

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468. Citing, *inter alia*, Transcontinental Gas Pipeline Corp., 55 FERC ¶ 61,339 at p. 62,004 (1991)

469. Citing CNG Transmission Corp., 51 FERC ¶ 61,158 at p. 61,433 (1990).

causation principles. However, given our limited legal flexibility,[470] and the fact that all Part 284 shippers will benefit from this rule, GSR costs will not be recovered exclusively from former sales customers. If recovery of such costs were so limited, very few sales customers would find it feasible to choose a nonpipeline merchant. The choices that the final rule offers would be diminished, and the benefits of increasing competition at the wellhead would not be fully realized. The Commission sought in Order No. 636 to authorize recovery of these costs from a broader class of customers, namely, all that utilize firm transportation service under a pipeline's Part 284 blanket certificate, and in this order will broaden that class even further to include Part 284 interruptible transportation customers. This class will include current sales customers, former sales customers, customers that reduce or terminate sales entitlements during restructuring, and those that do not. It will also include firm and interruptible transportation customers that have never been, and will probably never be, sales customers of the pipeline. However, in the Commission's judgment, this continues the general goal of spreading the costs of industry restructuring.

Moreover, surcharges and exit fees to recover GSR costs will not be permanent features of a pipeline's rate structure. They are one-time-only or short-term assessments necessary to effectuate the transition to a more efficient, competitive natural

470. *See* Associated Gas Distributors v. FERC, 893 F.2d 349 (D.C. Cir. 1989)(AGD-II). *cert. denied sub nom.* Berkshire Gas Company v. Associated Gas Distributors, 111 S.Ct.277 (1990)(use of purchase deficiency method to allocate take-or-pay costs violates filed rate doctrine); Columbia Gas Transmission Corp. v. FERC, 831 F.2d 1135 (D.C. Cir. 1987) (direct billing of deferred production-related costs under Order No. 94 violates filed rate doctrine); and Transwestern Pipeline Co. v. FERC, 897 F.2d 570 (D.C. Cir. 1990) (direct billing of unrecovered gas costs in Account No. 191 when PGA mechanism had been terminated violated filed rate doctrine).

gas market. Under the circumstances, the Commission believes that spreading the costs of the transition over a broader group of customers than those whose specific choices in restructuring give rise most directly to the pipeline's incurrence of those costs is equitable.

On the other hand, transportation service under individual Section 7(c) certificates is not directly affected by Order No. 636. The provision of such service will not give rise to any Order No. 636 transition costs, and the upgraded, open access transportation services required by the final rule generally will not benefit shippers under individual Section 7(c) certificates. Accordingly, the Commission will deny Philadelphia Electric's request for rehearing.

4. Recovery (or refund) of Account No. 191 balances

ANR requests clarification of the Commission's statement in Order No. 636 that recovery of Account No. 191 costs will be limited to costs accrued after July 31, 1991, the issuance date of the Notice of Proposed Rulemaking in this proceeding, based on the Commission's understanding of the court's decision in *Transwestern Pipeline Co. v. FERC.*[471] ANR argues that the Commission's action in eliminating the purchased gas adjustment (PGA) mechanism in Order No. 636 is distinguishable from the situation in *Transwestern* where the pipeline voluntarily sought direct bill recovery of the balance in its Account No. 191. ANR argues for 100 percent recovery of any balance in its Account No. 191 account when its PGA mechanism is eliminated without regard to any "cut off" date for accrual of its purchased gas costs.

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471. 897 F.2d 570 (D.C. Cir. 1990).

Appendix C

Carnegie seeks clarification that pipelines will not be limited to recovery of Account No. 191 costs *incurred* after July 31, 1991, but that the Commission's reference to costs "accrued" after that date means that pipelines may recover the accumulated balance after that date, regardless of when the costs were incurred. According to Carnegie, a substantial portion of the Account No. 191 balances of many pipelines is attributable to costs incurred before July 31, 1991, and preventing pipelines from direct billing those costs would impose severe losses. Furthermore, they argue, an interpretation limiting pipelines' recovery of such costs would be inconsistent with other statements in Order No. 636 and a statement in an April 28, 1992 letter from Chairman Allday to the President describing Order No. 636 as permitting pipelines "to direct bill *any* unrecovered balances in their purchased gas accounts upon converting to market-based pricing for sales."[472]

Peoples Natural Gas argues that under the decision in *Transwestern*, a pipeline may only direct bill Account No. 191 costs that were accrued into the account after the Commission has explicitly adopted a formula that qualifies as a rate under Section 4 of the NGA and indicates when it will take effect. According to Peoples Natural Gas, the date of issuance of the NOPR in this proceeding cannot serve as notice of a direct billing formula sufficient to satisfy the filed rate doctrine. The proposal was simply a proposal, Peoples Natural Gas argues, to authorize direct billing as a generic concept, and did not announce any particular allocation methodology or formula, so that customers were not informed in even the most rudimentary way of the consequences of direct billing by any particular pipeline.

When a pipeline terminates the operation of its PGA

472. CNG makes the same arguments in a request for clarification.

mechanism, its Account No. 191 balance will either be positive or negative. A positive balance in a pipeline's Account No. 191 is a reflection of unrecovered costs of purchasing gas for a prior period. Customers that purchase gas from a pipeline with a PGA mechanism in its tariff are on notice that they are potentially liable in future periods for payment of unrecovered purchased gas costs that are attributable to current service. If it is negative, the sales customers are entitled to a refund of the pipeline's overrecovery of its purchased gas costs in prior periods. As long as the PGA mechanism remains in place, refunds are made pursuant to the terms of the mechanism itself. When it is terminated, they are made pursuant to any provisions of the pipeline's tariff that provide for disposition of the Account No. 191 balance, or if there are no such provisions, pursuant to Commission order.

The Commission argued in the *Transwestern* case that if a PGA mechanism is terminated leaving a positive balance of unrecovered gas costs in Account No. 191, the pipeline should be entitled to render a final bill to its sales customers to complete recovery of its gas costs for service rendered in prior periods, even if the pipeline's tariff did not have specific provisions for final disposition of such balances in effect when such costs were accrued. In the Commission's view, Transwestern's PGA mechanism, by its very nature, provided adequate notice of customers' potential liability for a positive balance in Account No. 191 upon termination of the mechanism. The court disagreed, holding that the PGA regulations promulgated in 1972 and certain more recent cases authorizing direct billing of Account No. 191 balances did not provide sufficient notice of customers' liability for such direct billing to satisfy the filed rate doctrine. Accordingly, the court disallowed recovery of Transwestern's unrecovered purchased gas costs that accrued before the date the Commission approved Transwestern's

certificate providing for such direct billing upon termination of its PGA mechanism.

The Commission expects pipelines will terminate their PGA mechanisms under Order No. 636 and initiate market-based pricing of gas in order to remain competitive in the sales market after full compliance with restructuring.[473] Accordingly, and in light of the court's decision in *Transwestern*, the Commission gave notice in the NOPR in this proceeding, and again in Order No. 636, to all sales customers of affected pipelines of their liability for any unrecovered balances in those pipelines' Accounts No. 191 upon termination of their PGA mechanisms in connection with restructuring.

Before the Commission's decision in *Transwestern*, pipeline sales customers may not have known that they would be liable for direct bills upon termination of a PGA mechanism. It was the absence of notice of such potential liability, and not the absence of a specific formula for determining the amount of the future direct bills that the court found violated the filed rate doctrine. However, the Commission considers the notice of the Commission's policy on this issue in the NOPR to be adequate notice to permit direct billing of all costs that accrue after that date by all pipelines affected by this proceeding. Furthermore, the Commission does not anticipate that pipelines will have any unrecovered gas costs that accrued before July 31, 1991, by the time they come into full compliance with Order No. 636 and terminate their PGA mechanisms. Most pipelines have already recovered their pre-July 31, 1991 costs, and for those that have not, there is ample opportunity to recover such costs through the operation of their PGA mechanisms before they implement

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473. However, pipelines are not prohibited from negotiating cost-tracking systems with their customers.

their restructuring filings in time for the 1993-1994 winter heating season.

The Commission stated in Order No. 636 that pipelines must permit customers to pay the direct bill for Account No. 191 costs in either a lump sum, over twelve months, or over some other reasonable period of time, at the customer's option. K N Energy asks for clarification that pipelines will be able to collect carrying charges if the payment of the principal amount of the direct bill is amortized over a period of time. K N Energy asserts that the Commission's consistent practice has been to permit recovery of carrying costs.[474] The Commission grants the requests for clarification by K N Energy. A pipeline will be entitled to collect carrying charges on the unrecovered balance of a direct bill that a customer elects to pay in installments at the same rate that would apply to unrecovered balances in Account No. 191.

United Distribution Companies seek clarification that customers may challenge the level and makeup of the balance remaining in Account No. 191 on its termination apart from the issue of the pipeline's prudence in its purchasing practices. They suggest that a pipeline, recognizing that it will have an opportunity to recover prudently incurred Account No. 191 costs, may be tempted to sell its gas supplies at low cost, thereby inflating the Account No. 191 balance. This would not be prudent, according to United Distribution Companies, and customers should have the right to challenge the content of Account No. 191 in such an event. Northern Indiana argues that pipelines should not be allowed to direct bill Account No. 191 balances to its former sales customers that reflect the costs of gas incurred to balance receipts and deliveries of its transportation customers.

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474. Citing, *inter alia*, Trunkline Gas Company, 58 FERC ¶ 61,340 (1992).

The Commission grants these requests for clarification. Customers of a pipeline terminating its PGA mechanism and proposing to direct bill the unrecovered gas costs in its Account No. 191 will have the same rights to challenge the makeup of contents of the account, including costs attributable to the pipeline's transportation service, as they would have in a review of any annual PGA filing.

The Tennessee and Columbia Small Customers assert that recovery of commodity-related Account No. 191 costs based on gas purchases for the twelve months preceding the effective date of service under the unbundled sales certificate, and the recovery of demand costs based on CD on the day before the effective date of restructured services, will have a disproportionate and unfair impact on small sales customers, because many of the larger customers have converted to transportation in the past several years. The small customer groups argue that unrecovered PGA costs should be recoverable from all customers who were sales customers of the pipeline during the period the costs were actually accrued. The Commission has already indicated in Order No. 636 that pipelines or other parties could propose other mechanisms for allocating the Account No. 191 costs to be direct billed, if the described mechanism is inequitable.[475] Accordingly, there is no need to grant rehearing on this issue.

5. Challenges to a pipeline's prudence

In Order No. 636, the Commission stated that a review of a pipeline's prudence in incurring GSR costs would include an examination of whether the contract terms were reasonable in light of the market conditions existing when the contract was

475. Order No. 636 at p. 30,458, n. 283.

negotiated, renegotiated or terminated. NGSA maintains that the language is confusing and could be interpreted to mean that the prudence of contracts renegotiated under the provisions of Order Nos. 500 or 528 could be challenged in connection with their reformation a second time under Order No. 636. Since pipelines that filed for recovery under Order Nos. 500 or 528 absorbed a portion of the contract renegotiation costs involved, and were afforded a presumption of prudence in the incurrence of such costs, NGSA argues that the renegotiated contracts should also be accorded a presumption of prudence in proceedings to recover GSR costs under Order No. 636.

In Order No. 636, the Commission stated that it was not proposing a new prudence standard for review of a pipeline's GSR costs, but also said that its primary objective in any prudence review of such costs would be to determine that the total amount is as minimal as possible. K N Energy, Inc. is concerned that the "as minimal as possible" standard is not the Commission's historical prudence standard of the "reasonable man" test, and requests the Commission to clarify that the applicable test in prudence reviews of GSR costs will be the "reasonable man" test set forth in *New England Power Company*.[476] If the Commission declines to so clarify, K N Energy seeks rehearing, claiming that the Commission has impermissibly deviated from its consistent practice without reasonable explanation. Marathon raises the same issue, arguing that the Commission must resolve how a contract once deemed reasonable is now subject to a reassessment on the same issue.

Tenneco suggests various regulatory incentives for producers to make concessions in reforming their supply

476. 31 FERC ¶ 61,047 at pp. 61,081-84 (1985), *aff'd*, Violet v. FERC, 800 F.2d 280, 282-83 (1st Cir. 1986).

contracts with pipelines. If the Commission does not implement any of these incentives, and does not permit pipelines to implement any of them, Tenneco asks the Commission to explicitly find that pipelines are prudent if they are able to negotiate a buyout or buydown that is equal to or less than a dollar for dollar settlement.

The Commission does not intend for challenges to a pipeline's prudence in incurring GSR costs to reopen prudence issues that have already been resolved. If a contract is renegotiated under Order No. 636 that had not been renegotiated under Order Nos. 500 or 528, interested parties may challenge the pipeline's prudence in entering into the contract in the first place, the prudence of its purchasing practices under the contract (assuming these issues have not been previously litigated), and the pipeline's prudence in renegotiating the contract under Order No. 636. However, if recovery of the costs of renegotiating a gas supply contract has been allowed under a take-or-pay filing made pursuant to Order Nos. 500 or 528, the renegotiation of the contract has been found to be prudent. If the same contract is renegotiated again under Order No. 636, interested parties may challenge the pipeline's prudence in the latter renegotiation, but not the former.

The Commission is not changing its historic standard or test for determining the prudence of a pipeline in purchasing gas supplies. However, as the Commission said in Order No. 636, prudence dictates that pipelines in restructuring proceedings negotiate vigorously and at arms length with their producer/suppliers in a *bona fide* effort to minimize transition costs.[477] A pipeline whose prudence is challenged will be judged on the basis of such effort.

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477. Order No. 636 at p. 30,459.

Appendix C

6. GICs and recovery of gas supply realignment costs

LILCO suggests an additional element for determining the prudence of a pipeline's GSR cost incurrence where the pipeline currently has a gas inventory charge (GIC), namely, whether the pipeline prudently used the dollars it has collected from the GIC to realign its gas supply contracts and thus reduce the GSR costs resulting from restructuring under Order No. 636. LILCO argues that a pipeline should not be permitted to recover 100 cents on the dollar of GSR costs if it has not used the proceeds from its GIC collections wisely and efficiently to reduce its above-market costs.

The Kentucky PSC seeks clarification that pipelines with GICs may not include amounts spent to resolve liabilities accrued when service was provided under the GIC as transition costs under Order No. 636, because GIC mechanisms were supposed to be the sole means for recovering costs necessary to buydown or maintain existing high cost gas supply contracts.

Gas Company of New Mexico asserts that pipelines with GICs had to forego any other method of recovering gas supply costs. Therefore, it argues, any pipeline that has contracts for sales at negotiated rates that include gas inventory charges should not be permitted to charge any otherwise eligible GSR costs to GIC customers unless the customer uses rights provided in Order No. 636 to modify its contract entitlements.

Gas supply costs for which GIC charges have been collected cannot be recovered again as transition costs. For this reason the Commission prohibits a pipeline with a GIC mechanism in place from filing under Order No. 528 to recover take-or-pay costs. However, a pipeline may incur GSR costs as a result of its customers' actions under Order No. 636 that could not have

been anticipated in designing the GIC and cannot be recovered through a GIC. For example, a pipeline may presently be incurring take-or-pay costs and recovering those costs with revenues from its GIC. The pipeline may need to shed the gas contract in order to be competitive in the post-restructuring world. Or the pipeline's customers may choose not to buy any gas from the pipeline after restructuring. The prudently incurred GSR costs attributable to terminating that contract would be eligible for 100 percent recovery under Order No. 636 if the pipeline demonstrates that customer actions pursuant to Order No. 636 caused the GSR costs, were not anticipated in the design of the GIC, and cannot be recovered by the GIC.

7. Small customer exemption, mitigation

The Tennessee and Columbia Small Customers request that small customers be exempt from transition costs associated with restructuring under Order No. 636, particularly the costs of contract realignment and extinguishment of Account No. 191. In the alternative, they request their share of transition costs to be reduced by 50 percent in accordance with the policy for reallocating take-or-pay costs away from small customers under Order No. 528-A.[478] These small customer groups argue that they will not significantly benefit from unbundling and comparability of service under Order No. 636, that they are less able to bear transition costs than other, larger customers, and that service to small customers will not cause pipelines to incur material levels of transition costs. These groups assert that because of their purchase levels, load factor characteristics, the small size of their staffs, and the lack of time, training and experience relative to purchasing gas, they will be hard pressed

478. Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 54 FERC ¶ 61,095 at p. 61,300 (1991).

to maintain the same service levels after restructuring without paying much higher rates. These groups predict that the increased rates will prompt many of their customers to switch to alternate fuels — wood, propane, kerosene, and coal — and that other customers that cannot switch will be burdened with undue economic hardship. The National Association of Gas Consumers also requests that small customers be exempt from transition costs because they will not benefit from restructuring, and will be harmed by increased rates. According to this association, the Commission should state, at a minimum, that small LDCs are free to negotiate a reduction or elimination of transition costs.

In this order, the Commission has modified the final rule in several ways described above to ensure the ability of small customers to secure the benefits of restructuring and mitigate any adverse effects. In view of these significant modifications — including the shift of 10 percent of GSR costs to be recovered through Part 284 interruptible transportation service — small customers should not be unduly burdened by transition costs on most pipeline systems.

8. Special issues concerning downstream pipelines

National Fuel raises several concerns about recovery of transition costs by downstream pipelines. In general, National Fuel urges that downstream pipelines should be authorized to recover 100 percent of the transition costs billed by upstream pipelines on an "as-billed" basis.[479] If a downstream pipeline is direct billed by (or receives refunds from) the upstream pipeline

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479. CNG seeks assurances that the Commission does not expect downstream pipelines to absorb any portion of the transition costs billed to them by upstream pipelines.

before its own restructuring filing is implemented, National Fuel urges that the downstream pipeline should be authorized to accumulate the amounts billed or refunded for subsequent distribution when its own PGA mechanism is terminated. Conversely, National Fuel notes that PGA balance direct bills or refunds may be received by a downstream pipeline *after* its compliance filing has been acted on by the Commission. In that event, according to National Fuel, the downstream pipeline will need a PGA "trailing" mechanism or alternative flowthrough procedure to recover these amounts from (or make refunds to) its former sales customers.

Various pipelines have tariff mechanisms for tracking changes in their transportation costs (Account No. 858). Since the balances in such tracking accounts reflect costs incurred by the pipeline in its capacity as a provider of bundled merchant service, National Fuel argues that they should be treated the same way the Commission treats the Account No. 191 balances. National Fuel also argues that recovery by downstream pipelines of upstream transition costs should not be delayed pending completion of the downstream pipeline's restructuring proceeding.

The Commission does not intend for downstream pipelines to have to absorb any of the transition costs billed to them by upstream pipelines. Accordingly, downstream pipelines will propose mechanisms for flowing through those costs to their own customers. Account No. 858 balances may be direct billed the same way as Account No. 191 balances. Such mechanisms must be included in the downstream pipeline's compliance filing in its restructuring proceeding. Mechanisms should be devised for application in various scenarios — when the upstream pipeline's restructuring is implemented before or after that of the downstream pipeline. Downstream pipelines may not recover

any transition costs from their own restructuring until they have fully complied with the requirements of Order No. 636, but they will not be precluded from flowing through transition costs from upstream pipelines while their own restructuring proceedings are still pending. However, such upstream pipeline transition costs must be clearly identified as such and separately identified on the bills from the downstream pipeline's own Order No. 636 transition costs in order to ensure proper treatment of the latter costs.

9. Challenges to prudence of LDCs' actions in restructuring proceedings.

South Carolina Pipeline Corporation (South Carolina Pipeline) requests the Commission to clarify or retract Order No. 636's language in footnote 288 pertaining to prudence challenges before state regulatory agencies to LDCs' actions in restructuring proceedings. South Carolina Pipeline asks for clarification of several alleged ambiguities in the language of that footnote, and asserts that the Commission erred in inviting states to engage in prudence reviews of the actions of LDCs in restructuring proceedings. South Carolina Pipeline asserts that any attempted review in a state proceeding of an LDC's actions in restructuring proceedings or incurrence of GSR costs is constrained by the Supreme Court decision in *Nantahala Power and Light Co. v. Thornburg*,[480] which, according to South Carolina Pipeline, guarantees LDCs passthrough at the retail level of wholesale rates approved by this Commission. South Carolina Pipeline argues that the only potential exception to the pre-emptive effect of FERC-approved rates is the "*Pike County*

480. 476 U.S. 953, 970 (1986); *see also* Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

doctrine,"[481] under which state commissions may consider the wisdom of a utility's purchase from among several alternate sources where the utility initially had a choice. However, according to South Carolina Pipeline, this exception does not apply to the types of costs involved under Order No. 636, because they could not have been nor can they be avoided by the LDC.

PG&E also requests that footnote 288 be deleted because of the likelihood it will be misinterpreted by state commissions in a manner inconsistent with applicable law under *Mississippi Power & Light Co.* and *Nantahala*. PG&E argues that, even though the Commission, for policy or equitable reasons, may not want its order to have the preemptive effect of requiring state regulatory agencies to permit passthrough of Order No. 636 transition costs approved by the Commission, that preemptive effect derives from the filed rate doctrine and the Natural Gas Act, as interpreted by the Supreme Court, and the Commission has no power to waive the doctrine or consequences of its decisions.

Footnote 288 simply stated existing law: state commissions should determine prudence challenges to LDCs under their jurisdiction in accordance with applicable state and federal law. The Commission observes that LDCs will have some critical decisions to make during the restructuring proceedings — *e.g.* whether or not, or to what extent, to exercise their rights to reduce or terminate their sales entitlements under existing contracts, and arrange for alternate gas suppliers. The Commission does not intend to preempt state commissions from determining whether those customers were prudent in making those decisions during restructuring proceedings. This is consistent with the so-

481. Pike County Light and Power Company v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-38 (1983).

called "*Pike County* doctrine" respecting purchasing decisions, not contrary to it.

10. Exit fees as a deterrence to competition

Northern Illinois Gas reminds the Commission that in its comments on the NOPR, it warned that the exit fee process could be used to insulate pipelines from competitive pressures and to defeat the underpinnings of a final rule. Now it alleges that the exit fees proposed in the April 23, 1992 filing by Natural are so high, and for so long a term, that Natural would be able to reap monopoly profits for its post-Order No. 636 sale services and impose contractual terms that would prevent competition from ever developing on its system. Natural Gas Clearinghouse and Tejas object to exit fees for recovery of GSR costs that are imposed only on those historical sales customers that choose to reduce or eliminate pipeline purchases. According to Natural Gas Clearinghouse, such exit fees eliminate the free nomination rights promised by Order No. 636, place competing suppliers at a distinct disadvantage vis-a-vis the pipeline merchant, and are no different than the minimum bills which have been consistently outlawed by the Commission since the issuance of Order No. 380.[482] Tejas requests clarification that any exit fees must apply to all former pipeline sales customers, irrespective of who they choose to buy gas from in the post-restructuring market.

The Commission will not address Northern Illinois Gas's arguments against Natural's exit fee proposal in this order. Natural's proposal will be considered together with its

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482. Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 FR 22,778 (June 1, 1984), FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,571.

compliance filing in its restructuring proceeding.[483] In Order No. 636, the Commission provided that pipelines and their customers *could* negotiate exit fees in lieu of, or in combination with a surcharge on reservation fees for recovering GSR costs.[484] Exit fees were also *suggested* as a means for a firm capacity holder to compensate a pipeline for the release of capacity during restructuring where there is no other customer willing to assume liability for the maximum rate for the released capacity.[485] The Commission did not, however, authorize the unilateral imposition of exit fees on a customer that is reducing or terminating sales, but is not reducing its reservation of transportation capacity. Accordingly, the fears of Natural Gas Clearinghouse and Tejas that unilaterally imposed exit fees may function as a minimum bill and deter customer selection of alternative suppliers are misplaced.

With Natural's proposal in mind, Northern Illinois Gas requests, among other things, that pipelines not be allowed to recover the costs of buying out of all their gas supply contracts for the purpose of abandoning the merchant function. According to Northern Illinois Gas, buying contracts down to price levels that reflect long-term firm contract prices may be a legitimate need under Order No. 636, but the costs of abandoning the merchant function altogether is not related to Order No. 636.

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483. Natural Gas Pipeline Company of America, 59 FERC ¶ 61,251 (1992).

484. Order No. 636 at p. 30,457.

485. Order No. 636 at p. 30,454. As long as a sales customer remains on the system as a firm transportation customer of the pipeline, the pipeline has no need of an exit fee, because it can recover a portion of the GSR costs through the demand surcharge.

Appendix C

Pipelines must act prudently to minimize their transition costs. If all customers terminate their sales entitlements during restructuring, a pipeline may have to buy out all of its gas supply contracts and wholly abandon the merchant function, and the prudently incurred costs of such buyouts, to the extent they were attributable to Order No. 636, would be fully recoverable. But a pipeline's costs of buying out of all of its supply contracts, simply because it chooses to get out of the merchant business, and not because its customers so choose, would not be fully recoverable as GSR costs.

11. Columbia's producer contract rejection costs

Columbia and the Official Committee of Unsecured Creditors of Columbia Gas Transmission Corporation (Columbia Unsecured Creditors) urge the Commission to recognize the recoverability of the costs that Columbia will incur as a result of its rejection of various producer contracts in its pending bankruptcy proceeding. Columbia argues that its producer contract rejection costs should be treated as GSR costs under Order No. 636, because they would have been incurred as such costs in the absence of Columbia's actions in the bankruptcy. Columbia is concerned that the Commission may disallow 100 percent recovery of its producer contract rejection costs because they were incurred before issuance of Order No. 636, and thus independently of the final rule. Columbia Unsecured Creditors seek clarification that the Commission will permit recovery of Columbia's gas supply realignment costs either through existing recovery mechanisms or through the new mechanisms established for GSR costs in Order No. 636. The unsecured creditors argue that Columbia's gas supply realignment costs, in the form of producer contract rejections costs, are attributable to the Commission's ongoing regulatory reforms, including Order No. 636.

UGI takes the position that Columbia's producer contract rejection costs are not the consequences of Order No. 636, but stem solely from Columbia's failure to bring its gas supply into line with pre-Order No. 636 market conditions.

As already discussed above, gas supply realignment costs not attributable to restructuring Order No. 636 cannot be recovered as Order No. 636 transition costs. Since this issue or how to treat costs incurred pursuant to rejections of producer contracts in a bankruptcy proceeding is specific to Columbia, the Commission will not address it in this order on rehearing. The issue may be presented by appropriate pleadings in a Columbia proceeding.[486]

12. Great Plains synthetic gas

Several parties raise concerns with respect to the recovery of the cost of synthetic natural gas (SNG) purchased from the Great Plains Gasification Project (Great Plains). In Order No. 636, in response to the comments of the Dakota Gasification Company, the owner of Great Plains, the Commission noted that in the Transco proceeding in Docket No. CP88-391-004, *et al.* (*Transco*),[487] the Commission approved a settlement that provided for a volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to Transco's obligations to purchase synthetic gas from Great Plains. The Commission stated that it would consider any proposals in the restructuring proceedings of the other

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486. Similarly, Columbia's questions concerning the recoverability of its PGA surcharge under a 1985 settlement are not appropriate for resolution in this generic rulemaking.

487. 55 FERC ¶ 61,446 (1991).

pipelines that purchase synthetic gas from Great Plains, in addition to Transco, for a special billing mechanism and special treatment for the associated transportation capacity for Great Plains gas consistent with the precedent in Transco's global settlement.

The Industrial Groups request clarification that the Commission has not decided in Order No. 636 how these costs shall be recovered, but has instead left that issue for decision in individual restructuring proceedings. In the alternative, if the Commission does not grant the requested clarification, the Industrial Groups urge the Commission to grant rehearing on this issue and to require recovery from converting sales customers only.

Natural maintains that because of intense competition, it would not recover Great Plains coal gas costs if recovery were through a volumetric surcharge. Consequently, Natural requests the Commission to clarify that Order No. 636, while permitting the *Transco* approach, does not require it. Similarly, Tenneco requests the Commission to clarify that it is not precluding recovery of the above-market premiums under the Great Plains contract through a fixed charge across all services.

On the other hand, the State of Michigan argues that the Commission erred by not foreclosing ratepayer subsidization of uneconomic SNG. Similarly, the Wisconsin Distributor Group maintains that the concept of permitting special cost recovery for above-market, inefficient synthetic gas supply costs is contrary to the goals of Order No. 636 to stimulate the domestic natural gas market and to provide customers access to market-priced gas supply.

The Commission recognizes that providing a special cost recovery mechanism for these gas supplies departs from the market-oriented goals of Order No. 636, but it is consistent with the Commission's goal of providing a smooth transition from the prior regulatory environment to the new market-oriented environment. This is particularly appropriate with respect to Great Plains gas because of the special circumstances and government involvement surrounding the Great Plains project. As in *Transco*, the Commission concludes that it is "reasonable for all of [the pipeline's] customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users . . . by increasing the supply of available gas."[488] Thus, the Commission adheres to its discussion on this issue. The Commission will consider any proposal by the pipelines for recovery of the costs of Great Plains gas, whether or not modeled on the proposal approved in *Transco*.

13. LDC bypasses

A number of parties raise various concerns with respect to LDC bypasses. Several parties (United Distribution Companies, Northern Illinois Gas, and the State of Michigan) assert that the Commission should have established a policy or rule requiring that transition costs follow bypassing customers and/or providing LDCs with relief in bypass situations such as a reduction in contract demand with the pipeline. On the other hand, the American Paper Institute and the Fuel Managers Association maintain that the Commission erred in providing an opportunity for LDCs to obtain relief in the event of a bypass. They assert that offering LDCs relief from bypass is protecting them from competitive forces and is contrary to the principles of competition discussed in Order No. 636.

488. 55 FERC ¶ 61,446 at p. 62,341 (1991).

CNG asserts that because pipelines may confront bypass situations identical to those confronting LDCs, the Commission should clarify that pipelines may request the same relief as LDCs.

Finally, the Iowa, Missouri and Wisconsin Commissions maintain that the Commission's proposed burden of proof on LDCs is misplaced. They urge that once an LDC shows that it has historically supplied a customer that is seeking to bypass its system, and has identified a rational method for allocating to that customer a portion of the transition costs that the LDC is required to bear under Order No. 636, then the burden should shift to the customer that is bypassing the LDC system to show that the proposed allocation is unreasonable or inequitable and that another allocation is more equitable under the circumstances.

The Commission adheres to its views on this issue as set out in Order No. 636. The Commission will consider requests for relief on a case-by-case basisin the context of the new regime of this rule, but will not adopt a policy that would grant automatic relief in all circumstances. The factual circumstances surrounding an LDC bypass differ sufficiently that the Commission cannot justify a generic rule that would be appropriate in all circumstances.

Finally, contrary to the assertions of the state regulatory commissions, the Commission believes that it is fair for an LDC seeking relief in a bypass situation to show that there is a direct nexus between the bypass and the pipeline, so that the costs it seeks to avoid should be reallocated to the bypassing customer. On the other hand, the Commission will not allow bypass to be used simply as a means of avoiding the bypassing company's fair share of transition costs.

Finally, the Commission denies CNG's request for clarification. The Commission has provided pipelines a meaningful opportunity to recover their prudently incurred transition costs. The Commission does not believe it is appropriate for pipelines to obtain additional transition cost recovery on a case-by-case basis every time a shipper switches from one pipeline to another.

14. Miscellaneous

a. Non-cash consideration as GSR costs

PSE&G requests clarification that if pipelines realign their producer supply contracts by providing for discounted transportation or other non-cash consideration, they will not be allowed to recover the costs of such settlements as GSR costs.

The precedents under Order Nos. 500 and 528 governing recovery of non-cash consideration to reform gas supply contracts are applicable.[489]

b. Alternative recovery mechanisms

United Distribution Companies argue that Order No. 636 unduly restricts parties from negotiating alternative methods of

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489. *See* ANR Pipeline Company, 48 FERC ¶ 61,140 (1989)(non-cash consideration to settle take-or-pay contracts was recoverable through a take-or-pay recovery mechanism if it met the known and measurable standard). However, the only costs of transportation discounts that are recoverable through a take-or-pay mechanism are the costs of discounting below the level of discount that the pipeline is giving other shippers at the time for competitive reasons. Natural Gas Pipeline Company, 51 FERC ¶ 61,190 (1990), and United Gas Pipe Line Company, 51 FERC ¶ 61,320 at p. 62,065 (1990).

transition cost recovery. CNG LDCs agree, and urge the Commission to withdraw its prescribed recovery mechanisms for transition costs, and grant the parties an opportunity to negotiate the means by which transition costs are to be recovered.

Order No. 636 does not preclude parties from voluntarily agreeing to alternative mechanisms on the basis of the pipeline's particular circumstances. However, in the absence of such voluntary agreement between the pipeline and the parties, Order No. 636 will control.

Western Resources (formerly KP&L) asserts that its pipeline supplier, Williams Natural Gas Company, entered into its gas supply contracts to serve both its firm and interruptible customers, and that many current shippers were interruptible sales and non-jurisdictional customers prior to Williams' transition to open-access transportation, and argues that GSR costs should be recovered through a volumetric surcharge to reach those customers.

As discussed above, interruptible shippers under a Part 284 blanket certificate will be subject to an interruptible rate that recovers 10 percent of a pipeline's GSR costs. Furthermore, as discussed below, when a pipeline unbundles its direct, non-jurisdictional sales, the unbundled transportation will be provided under the pipeline's Part 284 certificate, and will be subject to surcharges to recover Order No. 636 transition costs.

c. Recovery of GSR costs through direct bill or exit fee

Phillips urges that 50 percent of GSR costs and stranded facility transition costs should be recoverable through a direct

bill or exit fee and that 50 percent should be recoverable through a demand surcharge.[490] Phillips alleges that in today's market, all transportation costs, including demand surcharges, are typically "netted-out" from the prices producers receive at the wellhead. According to Phillips, using a 100 percent demand surcharge mechanism to recover GSR costs and stranded facility costs could leave producers absorbing the lion's share of the two largest elements of transition costs.

For most gas sales, a demand surcharge will have no effect on the purchaser's decision to buy a certain increment of gas and will not affect wellhead prices. A customer that has entered a long-term contract is obligated to pay the monthly demand charges, and any demand surcharges, regardless of whether it purchases any gas, and regardless of what price it pays for the gas. In Order No. 636, the Commission provided that exit fees for recovery of GSR costs could be negotiated. However, the Commission will not require customers to pay exit fees or permit them to direct bill for the recovery of GSR costs.

d. Effects of existing settlements on transition cost recovery

Washington Gas seeks clarification that Order No. 636 does not void existing settlements approving restructuring and transition cost recovery, but that the viability of the settlements, in whole or in part, will be tested and determined in the separate pipeline restructuring proceedings. Washington Gas urges the Commission not to dismiss the possibility that existing

490. The Commission in Order No. 636 did not prescribe any generic recovery mechanism for stranded costs, but merely provided that pipelines could propose an appropriate means of recovering all prudently incurred stranded costs in a general rate filing under section 4 of the NGA.

settlements already reflect the maximum degree of achievable unbundling consistent with certificated firm service levels under Section 7(c) of the NGA and prudent and reasonable transition cost levels. Washington Gas argues that any determination of the continued viability of existing settlements, and any findings that they violate Section 5, should be made at the end, not at the beginning, of the restructuring proceedings. BG&E also seeks clarification that previously approved Order No. 528 settlements remain binding and govern the treatment of any gas supply realignment or similar costs that fail to pass the Order No. 636 eligibility review.

Atlanta Gas also seek assurances that ceilings under existing take-or-pay settlements will not be disturbed by permitting recharacterization as GSR costs under Order No. 636, nor will the protection against abandonment negotiated in the settlement of Transco's restructuring be disturbed.

As noted in Order No. 636, the relationship between provisions of existing settlements and the provisions of Order No. 636 will have to be examined on a case-by-case basis. The Commission has and will provide all interested parties with an opportunity to present arguments on this issue on a pipeline by pipeline basis. However, as Washington Gas recognizes, settlements, like any other contracts, may be subject to revision if necessary to remedy violations of the NGA. However, Order No. 636 is not intended to affect the provisions of existing settlements governing recovery of take-or-pay costs under Order Nos. 500 and 528.

e. Credit for taking assignment of supply contracts

Illinois Power seeks clarification that customers taking

assignments of producer contracts will receive a credit against the transition costs otherwise allocable to them.

To avoid transition costs the Commission strongly encourages pipelines and parties to consider assignment of their gas supply contracts in their restructuring proceedings, where such assignments are mutually beneficial as a way of avoiding transition costs. However, the details of how the customers that accept such assignments should be treated in comparison to those that do not, as far as responsibility for transition costs, must be worked out in the restructuring proceedings.

f. Transition cost recovery and retroactive ratemaking

The National Association of Gas Consumers argues that GSR costs, Account No. 191 costs remaining when a PGA mechanism is terminated, and "stranded costs" are past costs that will not recur during the period that the restructuring rates will be in effect, and that the ban on retroactive ratemaking prohibits collections of these costs from consumers.

The ban on retroactive ratemaking should not prevent pipelines from recovering any of the transition costs arising from restructuring. GSR costs are the costs of reforming supply contracts under which gas will be available on a current basis. Unrecovered purchased gas costs relate to gas purchases in a prior period, but are recoverable on a deferred basis pursuant to the notice in this proceeding's NOPR (and elsewhere) of pipeline customers' direct bill liability for such costs upon termination of the PGA mechanism. Liability for stranded costs is based on the availability of the pipeline's facilities for future use by the system even though they are not directly assigned for use by a specific customer.

g. 100 percent recovery by pipelines and the "used and useful" principle

The CPUC argues that requiring a pipeline's customers to bear all of the transition costs is contrary to the "used and useful" principle discussed in Order No. 528-A as a justification for requiring equitable sharing.

The Commission has described the reasons for its different policies for Order No. 528 costs and Order No. 636 costs, *supra*. The analogy described in Order No. 528-A between pipelines' high-cost take-or-pay contracts and certain failed gas supply projects, which the Commission had concluded were not used and useful, does not apply to the transition costs recoverable under Order No. 636, which will be incurred as a result of the options granted to pipelines' customers and the improved quality of transportation services required under the provisions of that order.

h. Sunset date for GSR costs and Order No. 528 costs

The Illinois Commerce Commission urges the establishment of a sunset date on GSR cost recovery mechanisms because, it argues, as long as pipelines have the right to retroactively bill customers for these costs, they will be in a preferred position relative to other merchants.

While the Commission in Order No. 636 did not impose a sunset date for making filings to recover GSR costs, it encouraged parties to the restructuring proceedings to establish such dates on a case-by-case basis. Furthermore, the Commission indicated its intention to audit each pipeline's gas supply contracts three years after the effective date of the final

rule, to ensure the pipeline's diligent realignment efforts, unless the pipeline had agreed to a sunset date in the interim.[491] The availability of Order No. 636 surcharges on transportation to recover GSR costs is also limited, as noted earlier, to those costs attributable to customers' decisions during restructuring.

Tejas claims that the Commission has apparently determined that, at some future date, the types of costs recoverable under Order No. 528 will become Order No. 636 transition costs, in effect establishing a sunset date for Order No. 528, and argues that the Commission was arbitrary and capricious in establishing such a sunset date *sub silentio*. Tejas urges the Commission to establish a rebuttable presumption that all GSR costs are appropriate for recovery under Order No. 528, rather than under Order No. 636, unless the pipeline proves otherwise by a preponderance of the evidence.

Tejas misunderstands Order No. 636 on this issue. Order No. 528 costs cannot "become" Order No. 636 costs. Furthermore, the Commission has not established a sunset date for filing to recover costs under Order No. 528. Until a pipeline is in full compliance with Order No. 636, it will recover its buyout and buydown costs under Order No. 528.

i. Firm transportation at fixed rates, discounts, and subject to caps

Tejas also objects to imposing demand surcharges on firm

491. Order No. 636 at p. 30,459, n. 286. The Commission will clarify, as requested by Texas Gas Transmission Corporation, that the Commission audit of a pipeline's recovery of its GSR costs can be avoided if the pipeline and its customers agree to a sunset date for filing for recovery of such costs within three years of the effective date of the pipeline's compliance filing, rather than from the effective date of Order No. 636 itself.

transportation customers that are not former sales customers. Tejas points out that, under Order Nos. 500 and 528, such customers were liable for volumetric surcharges, but not fixed charges. Under that policy, pipelines have agreed to provide firm transportation at fixed rates, and Tejas argues that the imposition of demand surcharges undermines the economics of those arrangements.

Firm transportation customers under a pipeline's Part 284 blanket certificate who pay more for firm transportation service enjoy the increased flexibility and reliability of the restructured firm service, plus the ability to release capacity more easily and efficiently, whether or not they have ever been sales customers of the pipeline. If a pipeline agreed to provide transportation service at a fixed rate, without a right to passthrough any surcharges or other cost increases, then the pipeline will have to bear the costs of the bargain it made.

Natural asserts that it sometimes has to discount reservation fees and therefore should be permitted to reflect an adjustment for costs which are not recovered due to discounting and to extend the recovery period. ANR asks for authority to direct bill some of its GSR costs, because it has negotiated rate caps with certain firm transportation customers that will preclude recovery of a demand surcharge.

The Commission will not relieve the pipeline of the consequences of the agreements it entered into to provide firm service at a discount or to bear the risk of increased costs for such service by permitting it to shift transition costs to other customers.

j. LDCs that buy gas from producers whose contracts they have paid to realign

The Pennsylvania PUC argues that it is inequitable to require LDCs to pay for the contract reformation costs incurred for gas not taken and then require them to go out and buy the same gas directly from the producer.

Customers will not be required to take assignments of gas supply contracts from producers, under Order No. 636. LDCs will have the option to purchase gas directly from producers or continue purchasing from the pipeline, whichever they determine is in their best interests. It is not inequitable for LDCs to pay for some portion of the pipeline's cost of reforming its supply contracts, since they will realize the benefit from the availability of market-sensitive gas prices under the reformed contracts if they continue purchasing from the pipeline, or even if they do not, because of the effects on competition of prices under the pipeline's reformed contracts.

k. Stranded costs

The Iowa, Missouri, and Wisconsin Commissions seek clarification that just because a cost fits Order No. 636's definition of a "stranded cost" does not mean that it was prudently incurred. Recovery of such costs should be disallowed, they argue, if they are the product of mismanagement, neglect, imprudence, or the like. The Commission grants this requested clarification.

The NASUCA argues that stranded investment costs are costs associated with physical plant that is no longer used and useful and should therefore no longer be includable in the rate

base. On the other hand, Williams seeks clarification that the cost of abandoning certain facilities that will no longer be needed for rendering its restructured services as a result of the capacity reallocation process will be fully recoverable as stranded costs.

LILCO asserts that creative pipelines will have opportunities to abuse Order No. 636's authorization to recover "stranded costs." For example, they can rid themselves of unused gathering facilities in declining production areas, underutilized upstream capacity, and capitalized lease payments on properties held for future development. LILCO asks the Commission to impose a strict eligibility test on stranded costs to preclude recovery of such costs.

Columbia asserts that some pipeline gathering and lateral facilities, and perhaps some products extraction facilities, will no longer be fully subscribed after restructuring, and requests the Commission to declare that the costs of such facilities may be recovered as stranded costs under Order No. 636. Columbia also seeks clarification that the costs of liquidating its system supply storage inventory will be recoverable as transition costs.

In Order No. 636, the Commission said that pipelines had to file to recover stranded costs in a general rate case. The Commission will consider arguments about whether particular facilities are used and useful, or whether the costs should be recoverable as transition costs, in the cases where the issues arise.

l. Excess royalty reimbursement clauses

The Minerals Management Service of the Department of the Interior (MMS) requests that pipelines be allowed to recover as GSR costs under Order No. 636 the costs that arise from

their contingent liability under earlier agreed to excess royalty reimbursement clauses. MMS says that it has decided to continue its past practice of requiring royalties to be paid on gross proceeds accruing to the producer from production, and that lessees have paid, and MMS has billed, and will bill, lessees of Federal and Indian lands for those portions of the take-or-pay settlement payments by pipelines that accrue to past or future production. Where pipelines included contingent excess royalty reimbursement clauses in their take-or-pay settlements with producers from such leases, they will be liable to reimburse the producers for such excess royalty payments. MMS is concerned that pipelines that have to make such payments to producers under their take-or-pay settlements may not be able to recover them under the provisions of Order No. 528 because of a December 31, 1990 sunset date, and urges the Commission to correct this apparent oversight by permitting recovery of such costs under the mechanism for Order No. 636 GSR costs.

As discussed above, there is no sunset date under Order No. 528. In addition, whether these costs are attributable to Order No. 636 restructuring will be decided on an individual pipeline basis.

m. Transition cost recovery from direct sales customers

The Industrial Gas Users Conference seeks clarification that the Commission may not require the imposition of transition costs under Order No. 636 on direct sales customers of a pipeline, because the Commission has no power to set direct sales rates.

Although the Commission lacks jurisdiction over direct sales of natural gas, it has jurisdiction over the transportation

component of direct sales,[492] and exercised that authority in Order No. 636 to require the embedded transportation service to be unbundled from the direct sales service.[493] Thus, transportation of direct sales gas from the unbundling point on pipelines with Part 284 blanket transportation certificates will necessarily be under the authority of that certificate and subject to the Commission's jurisdiction over Part 284 transportation rates.[494] Therefore, transition costs recoverable through surcharges on Part 284 transportation rates will be collectible from direct sales customers that use the pipeline's open access transportation service, like any other shipper.

n. Amortization period for recovery of GSR costs

The Fuel Managers Association requests the Commission to require pipelines to permit their firm transportation customers to extend their transition cost amortization period for at least fifteen years, subject to liability for the carrying costs. According to the Fuel Managers Association, such an extended amortization period will be very important to cogenerators and independent power producers who entered into long-term transportation contracts at fixed rates without anticipating a demand surcharge for GSR costs.

The Commission will not specify a minimum or maximum period for a pipeline to amortize the collection of its GSR costs,

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492. Mississippi River Transmission Corp. v. FERC, No. 91-1164 (D.C. Cir. July 21, 1992).

493. See the discussion of the Commission's legal authority over direct sales at III.A.3, and the clarification of the impact of Order No. 636 on direct sales at V.D.3.

494. *See* United Gas Pipe Line Company, 50 FERC ¶ 61,268 (1990).

but will leave that as a matter that must be resolved on a case-by-case basis. However, the Commission strongly encourages the parties to use a shorter-term amortization, such as a thirty-six month period, in order not to prolong the transition.

o. Bankrupt firm shippers and project-financed pipelines

Ozark Gas Transmission System (Ozark) wants a declaration that if the Commission rejects its other requests concerning existing shipper liability for released capacity, the Commission will permit the costs resulting from Ozark being declared in default of its indenture as a recoverable transition costs. Ozark asserts that the Commission must also address the situation where a firm shipper rejects its T-1 service agreement in a bankruptcy because it no longer needs the capacity as a result of Order No. 636, and Ozark is unable to collect the full amount of the minimum bill through that proceeding.

The Commission is granting the clarification requested by Ozark concerning releasing shippers' liability on project financed pipelines, as discussed below, thus alleviating Ozark's concern about default on its indenture. The question concerning a shipper in bankruptcy rejecting a service agreement can be dealt with when and if it arises in a proceeding.

p. Maximum bid to exclude demand surcharges

NGSA argues that firm customers should not be allowed to evade their responsibility for demand surcharges through the capacity reassignment process, and asks the Commission to expressly state that for purposes of capacity reassignment, the maximum bid shall not include the assignor's realignment surcharge.

NGSA's request is denied. For purposes of capacity reassignment, the maximum bid includes the assignor's realignment charge.

q. Downstream customers' liability for upstream pipelines' transition costs and capacity

LILCO requests the Commission to require a downstream pipeline's share of an upstream pipeline's transportation and transition costs to be allocated to downstream customers in proportion to their contract demand sales entitlement on the downstream pipeline. Furthermore, downstream customers choosing not to take the upstream capacity should be required to pay the net present value of their allocable share in the form of an exit fee.

The Commission will address this issue when it arises in individual pipeline restructuring proceedings.

r. Surcharge to recover new facilities costs

Questar asks that pipelines be permitted to implement a surcharge based on a balancing account to recover new facilities costs, because most of these costs will be incurred early in the restructuring process and pipelines should not have to defer recovery until they need to file a general rate case.

Pipelines should seek to recover the costs of new facilities necessary to implement restructuring in a general rate case as soon as they need to. The Commission will not adopt a special mechanism for the recovery of new facilities costs and will deny Questar's request.

s. Liability of pipeline under assigned gas supply contract

Marathon requests clarification that when a pipeline makes an assignment of a gas supply contract to one of its customers, the pipeline will remain liable on the contract unless the producer releases the pipeline.

Whether a pipeline remains liable to a producer under an assigned gas supply contract depends on the terms of the contract. The Commission's encouragement to pipelines to assign their gas supply contracts would not affect those terms.

C. Schedule and Procedures

1. Notice to all customers

The APGA requests rehearing of the requirement of Order No. 636 that all LDCs must participate in their pipeline supplier's restructuring proceedings or risk loss of their contracted-for capacity rights. APGA asserts that small publicly owned LDCs generally do not intervene and participate in Commission proceedings. APGA also states that many of the small LDCs will not receive actual notice of the pendency of their pipeline supplier's restructuring proceedings through publication of notice in the *Federal Register*. APGA urges the Commission to require pipelines to serve all of their customers with copies of the Commission's notice of its new restructuring proceedings, along with a clearly drafted letter explaining the extraordinary nature of these proceedings and the capacity rights that will be at stake. Furthermore, APGA requests that small customers be afforded leave to intervene out of time to protect their rights after they receive actual notice of the restructuring proceedings.

Appendix C

Under section 284.214(c), pipelines subject to Order No. 636 were required to initiate discussions by June 8, 1992, concerning restructuring, with *all* of their customers and other interested parties that had intervened in the restructuring proceedings. On May 22, 1992, the Secretary of the Commission issued a Notice of Procedures in all restructuring proceedings advising pipelines of their obligation under Rule 2010 of the Commission's rules of practice and procedure to serve a copy of their compliance filings on each person whose name is on the official service list, and any other person required to be served under law, or Commission rule or order. The Commission will clarify that a pipeline must serve a copy of its compliance filing in its restructuring proceeding on *all* of its customers, and the state regulatory commissions that regulate its customers, whether or not they have intervened in that proceeding.[495]

In Order No. 636, the Commission strongly encouraged interested parties to intervene and participate in restructuring proceedings before pipelines file their compliance filings, and indicated that motions to intervene after those filings are made would be viewed with disfavor. Publication of notice of the institution of the restructuring proceedings in the *Federal Register* constitutes sufficient notice to any interested party. Lack of actual notice of the proceedings will not be sufficient grounds for granting late interventions.

2. Extend the procedural schedule

APGA asserts that the truncated procedural timetable for

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495. *See* 18 CFR §§ 154.16 (Posting) and 154.22 (Notice requirements). This clarification is also responsive to the concerns raised by the Ohio Consumers' Counsel in its request for reconsideration of the May 22, 1992 notice.

implementing Order No. 636 will overwhelm the resources of all segments of the natural gas industry. Many parties will have to participate in restructuring proceedings on several pipelines simultaneously, and APGA asserts that it is not realistic to expect that this can be done well by the end of the year. The brief period for discussions between the pipeline's deadline for serving its implementation plan summary on July 7, 1992, and the deadlines for making compliance filings is the most troubling, according to APGA. Furthermore, APGA argues, the Commission has not allowed itself sufficient time for reviewing, analyzing, and approving or rejecting the compliance filings in time for the 1993-1994 winter heating season. According to the APGA, since the "no-notice" service on that LDCs will have to rely on to guarantee peak-day service to their customers is a new idea, yet to be fleshed out, the inadequate implementation schedule poses a threat to service reliability.

Cincinnati Gas argues that because of the intensely compressed implementation schedule dictated by Order No. 636, LDCs will be effectively deprived of the ability to make informed choices about their gas purchasing decisions, or take advantage of all opportunities for long-term sales contracts in a competitive market — one of the main rationales for mandating restructuring. According to Cincinnati Gas, negotiations with producers and marketers also take considerable time, even when very few LDCs are seeking similar arrangements, and the truncated schedule for implementing Order No. 636 will prompt LDCs to turn to the pipeline for merchant service, thus thwarting the underlying purpose of the order.[496] APGA and Cincinnati Gas both urge the

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496. Cincinnati Gas also expresses particular concern about having to begin negotiations regarding restructuring of the Columbia's system, while Columbia's bankruptcy is pending. The Commission has recently denied a motion by Columbia (supported by Cincinnati Gas) for an extension of its

(Cont'd)

Commission to extend the implementation schedule by at least twelve months.

The Industrial Groups urge the Commission to show more flexibility in implementing the restructuring program, and not to allow pipelines to force their restructuring plans upon unwilling parties to the restructuring proceedings, nor shirk its responsibility to protect the public from unreasonable terms and conditions of service. The Industrial Groups are concerned that unless parties are given reasonable extensions of time to achieve true settlements, pipelines may submit unilateral or minority settlements and leave it to the Commission to sort out the disputes. Tenneco asserts that the changes mandated in Order No. 636 are revolutionary in concept, and parties will need a considerable amount of time to decide on their positions with respect to the issues before they can come to the bargaining table.

After extended public input for over one year, Order No. 636 established certain deadlines for pipelines to initiate the process of implementing that order and stated its intention that pipelines complete the process in time for the 1993-1994 winter heating season. The Commission established deadlines from October 1, 1992 until December 31, 1992, for pipelines to make compliance filings, and expressed its view and expectation that pipelines and interested parties would achieve a consensus on most features of the restructuring filings before they are filed. The Commission also stated that it respects the rights of pipelines and interested parties to differ over how the provisions of Order No. 636 should best be implemented, and would establish

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deadline for making Order No. 636 compliance filings. Columbia Gas Transmission Corp., 60 FERC ¶ 61,047 (1992).

procedures to achieve expeditious resolution of any contested issues. Pipelines are required to propose effective dates for the *pro forma* tariff sheets they submit with their compliance filings, but the Commission will determine the effective dates of the tariffs in those filings on a case-by-case basis.

None of the requests for rehearing has presented any compelling reasons for an across-the-board postponement of the deadlines for pipelines making their compliance filings. And it is far too early for the Commission to determine whether there will be good reasons for delaying full implementation of Order No. 636 on a particular pipeline system beyond the 1993-1994 winter heating season. The transition required under Order No. 636 should be made by the entire pipeline industry in tandem, or as close in time as possible. In order to implement Order No. 636 successfully, all segments of the industry, and the Commission and its staff, will need to concentrate on the essential requirements of restructuring. Based on indications of activity in the restructuring proceedings so far, the Commission is confident that the natural gas industry can successfully concentrate its efforts in this regard, and that most pipelines, if not all, will be able to implement their restructured services within the time frame established by the final rule.

3. Implementing rate design changes under NGA Section 5

The Wisconsin Distributor Group argues that the Commission does not have authority to order pipelines to increase their rates in their restructuring compliance filings to implement the SFV rate design method. They argue that Section 5(a) of the Natural Gas Act prohibits the Commission from ordering an increase in any rate in a currently effective schedule, unless in accordance with a new schedule filed by the utility

under the provisions of Section 4 of the NGA.[497] Furthermore, they argue, a filing to implement SFV should be a major rate case under Section 4, requiring a full cost of service study, because implementation of SFV will affect substantially all of the jurisdictional rates, and will affect the pipeline's risk and various other assumptions underlying its current rates.

In Order No. 636, the Commission stated that where changes in rate design result in rate increases in certain components of the rates, or to certain customers or customer classes, even though they do not result in any overall increase in revenues, it would permit the increases in the compliance filing because it is related to a Commission directed modification in the pipeline's rate structure,[498] citing *ANR Pipeline Co. v. FERC*[499] as support for this authority. APGA argues that the *ANR* case does not support such authority, noting that the proceeding involved in that case, in which ANR was entitled to certain rate increases in connection with implementing an MFV rate design and eliminating its minimum bill, was initiated by the pipeline under Section 4.

In fact, that proceeding began with ANR's filing to implement a rate decrease under Section 4, but not to change its rate design. The Commission set the matter for hearing under both Section 4 and Section 5 of the NGA, which is its standard procedure, and ultimately made findings under the authority of Section 5 that ANR's rate design was unjust and unreasonable. ANR was ordered to revise its rates to implement the MFV rate

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497. Atlanta Gas presents similar arguments.

498. Order No. 636 at p. 30,465.

499. 863 F.2d 959 (D.C. Cir. 1988)

design method and to remove its minimum bill prospectively. When ANR made its compliance filing pursuant to the Commission's findings and order, it submitted an increased fixed-cost commodity charge to reflect the fact that with its minimum bill removed, the test period volumes for which it could bill would be fewer than the billable volumes under the minimum bill. Since ANR would no longer be recovering the minimum bill from one of its largest sales customers from which it collected a minimum bill during the test period, but which did not actually take all the volumes it had paid for under the minimum bill, ANR argued that it was entitled to a higher fixed-cost commodity charge in order to continue to recover all of its costs allocable to that charge from fewer billable volumes.

The Commission rejected ANR's increased commodity charge on the grounds that it was not authorized by the Commission's order requiring removal of the minimum bill and would violate the filed rate doctrine. The Commission further noted that ANR could file for a rate increase to reflect the reduced volumes under NGA Section 4.[500] The court of appeals reversed, concluding that the Commission had not rationally explained why its requirement that ANR's minimum bill had to be removed would not authorize the removal of volumes attributable to the minimum bill for purposes of calculating the amount of the fixed-cost commodity charge. In its order on remand, the Commission acknowledged its subsequent recognition of the principle that rate design revisions that require reductions in one component of a pipeline's rates will usually require simultaneous increases in some other component in order for the pipeline to recover its cost of service.[501] On remand, the

500. ANR Pipeline Company, 40 FERC ¶ 61,067 at pp. 61,204-5 (1987).

501. ANR Pipeline Company, 48 FERC ¶ 61,004 (1989), *citing* Tennessee Gas Pipeline Company, 46 FERC ¶ 61,113 at p. 61,443 (1989).

Commission conceded that ANR should have been entitled to reduce its design volumes and increase its fixed-cost commodity charge to compensate for its loss of revenue from the elimination of its minimum bill, and indicated that, but for the provisions of an intervening settlement, ANR would have been authorized to impose a retroactive surcharge to recover that revenue.[502]

Thus *ANR* stands for the proposition that when the Commission orders a pipeline to implement a different rate design method that requires reductions in one component of the pipeline's rates, it must permit the pipeline to implement offsetting increases in some other component simultaneously in order for the pipeline to recover its cost of service, unless there are good reasons for prohibiting the simultaneous increases and requiring the pipeline to implement the needed increases in a separate Section 4 proceeding.

The Commission does not see any good reason for generally prohibiting pipelines from implementing simultaneously the decreases and offsetting increases in rates necessary to effectuate the just and reasonable rate designs required under Order No. 636. The Commission in Order No. 636 specifically required the pipelines to design their rates using the cost of service and total throughput on which their rates in effect on the date of the compliance filing are based. Thus, the Commission is not ordering, but is rather prohibiting, any revenue increases to the pipeline. In ordering pipelines to file *pro forma* tariff sheets indicating how they propose to implement the requirements of Order No. 636, the Commission is not ordering any increase in rates. When the Commission concludes that a pipeline's tariff sheets and schedules are in compliance with Order No. 636, the Commission will generally exercise its discretion to *permit*, but

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502. 48 FERC ¶ 61,004 at pp. 60,010-11 (1989).

not *order*, the pipeline to implement any offsetting increases in rates, or components of rates, simultaneously with the necessary rate decreases, in accordance with the new tariffs and schedules filed by that pipeline. This procedure accords with the plain meaning of Section 5, established Commission practice, common sense, and court decisions on the issue.

4. Concurrent consideration of Section 4 filing for transition costs

INGAA argues that a mechanism for recovery of transition costs needs to be finalized in conjunction with the restructuring proceeding, preferably through a special rate filing, rather than a full blown Section 4 rate case. In INGAA's opinion, the final transition cost recovery mechanism developed in the rate proceeding should be part of the restructuring proceedings, and the Commission should not approve the compliance filing or settlement until the transition cost recovery mechanism is ready for implementation. K N Energy also suggests pipelines and their customers should be given an opportunity to reach a satisfactory resolution of the transition costs issues in the context of negotiated settlements in each pipeline's restructuring proceeding, and objects to the requirement that certain transition costs may only be recovered by filing a general rate case under Section 4 of the NGA. Southern also argues for concurrent resolution of transition cost recovery issues with all other restructuring issues because customers will not be able to make informed choices about service options until they know the transition costs that will flow from those choices.[503]

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503. Northern Indiana requests the Commission not to permit transition costs to be recovered under section 4 filings, so that recovery of such costs can be deferred until the Commission has determined they are just and reasonable.

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CIG asserts that under Order No. 636, pipelines will begin incurring transition costs essentially immediately, and will face immediate and tremendous revenue losses unless they can modify their rates to recover these costs. CIG urges the Commission to allow pipelines to file rates to recover their transition costs to become effective at the same time it accepts the pipelines' compliance tariff filings in their restructuring proceedings.

There are no insurmountable problems raised in these requests for rehearing, but also no simple answers. Pipelines are required to file their estimates of Order No. 636 transition costs and their proposals for recovery mechanisms as part of their compliance filings in the restructuring proceedings.[504] The mechanisms for recovering transition costs will be resolved in the restructuring proceedings, but the amounts to be recovered through those mechanisms will not.

Sales customers are permitted to reduce or terminate their sales entitlements during the restructuring proceedings, as well as release unneeded firm capacity if there is demand for it from other shippers, and to decide which of the pipeline's unbundled services they want, and what levels of service. The customers' choices will affect the pipeline's transition costs, and the estimated charges to recover transition costs will affect the customers' choices. Thus, the Commission recognized in Order No. 636 that the restructuring proceedings would necessarily be an iterative process.[505] Pipelines will have to realign their

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504. 18 CFR 284.14(b)(3)(iii). The amount of transition costs a pipeline may file to recover will not be limited by the amount of such costs it *estimates* in accordance with this section. (See CNG's request for rehearing.)

505. Order No. 636 at p. 30,455.

gas supply contracts in view of their sales customers' final choices and will be entitled to recover their prudently incurred costs of realignment pursuant to separate Section 4 rate filings. And pipelines may not begin collecting transition costs until after they are in full compliance with Order No. 636. The Commission will consider proposals by pipelines to initiate such recovery on a timely basis when such compliance is achieved.[506]

ANR seeks clarification that GSR costs may be recovered through *limited* Section 4 rate filings, and that such filings will not be suspended for more than one day, consistent with the Commission's practice for take-or-pay filings under Order Nos. 500 and 528. CNG also seeks to be able to file to recover *all* transition costs in a limited Section 4 filing at the time of restructuring or whenever they arise. CNG asserts that pipelines will be under extreme pressure to settle prudence challenges and will be forced to make substantial concessions or engage in costly litigation for the mere possibility of recovering their transition costs. Furthermore, CNG asserts that conditioning the possibility of transition cost recovery on full compliance with Order No. 636 will ensure protracted litigation initiated by consumers who will have virtually no incentive to resolve the dispute through settlement.

Carnegie asserts that it is unlikely to be able to recover 100 percent of its transition costs because only after it has fully implemented Order No. 636 will it be able to file to recover those costs. However, at that point, Carnegie asserts, its customers will have secured all the alleged benefits and will be in a position to challenge all transition costs without fear of losing any of the benefits. Tenneco requests the Commission to

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506. As discussed above, pipelines may file to recover GSR costs under the terms of Order No. 528.

establish streamlined procedures for challenges to prudence of GSR costs. Otherwise, they argue, the Commission will become mired in endless hearings on this issue.

CNG LDCs are concerned that the procedural schedule will not permit adequate time for consideration of challenges to a pipeline's prudence in incurring transition costs. CNG LDCs urge the Commission to follow a careful, case-by-case approach to the review of and subsequent implementation of the recovery of transition costs, even if it means going beyond the pipeline's Order No. 636 compliance filing date.

The Commission clarifies that pipelines may make limited Section 4 filings to recover GSR costs.[507] Ordinarily, such filings will be permitted to become effective after a minimum suspension. Long-term suspensions of collection under such filings would not benefit consumers because it would merely postpone the beginning of the amortization period for a fixed amount of recoverable costs, with interest accruable on balances until paid.[508] The Commission does not intend for customers to have to forego legitimate challenges to a pipeline's prudence in order to secure the benefits of restructuring. The possibility of such challenges constitute an important incentive for pipelines to negotiate vigorously to minimize their transition costs. Proceedings on prudence challenges are not constrained by any of the procedural deadlines of Order No. 636.

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507. Pipelines may also file to direct bill unrecovered balances in Account No. 191 in a limited Section 4 filing. Filing to recover stranded costs and new facilities costs must be made in the context of a general rate case. However, the Commission reiterates that there can be no recovery of transition costs until after the pipeline has fully complied with all the requirements of Order No. 636.

508. *See* Trunkline LNG Company *et al.* 59 FERC ¶ 61,342 (1992).

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The Commission expects to develop standards for evaluating pipelines' prudence in restructuring, and will be amenable to proposals for expediting final rulings on challenges to prudence.

Northern Illinois Gas urges the Commission to require each pipeline to file a new general rate case within a fixed period after restructuring in order to ensure that costs and throughput are adjusted to reflect the new services provided. It also argues that, irrespective of any refiling requirement, it is essential that pipeline rates be continuously adjusted to reflect assigned Account No. 858 and storage capacity, the impact on cost-of-service of other transition steps, the allocation of costs to the deregulated pipeline merchant function, and other changes in inputs and outputs produced by Order No. 636 compliance.

The statutory provisions of Section 4 and 5 of the NGA and the Commission's regulations are adequate to provide pipelines, as well as interested parties or the Commission, opportunities to initiate rate changes in contemporaneously with restructuring proceedings whenever anyone deems it necessary.

5. Using current cost of service and throughput for compliance filings

Cincinnati Gas asserts that after the restructuring proceedings, the pipelines' costs are likely to be significantly altered, depending on the disposition of such assets as upstream pipeline capacity, storage capacity, gas supply related costs and other factors. Furthermore, their mix of services and, necessarily, their throughput will bear little resemblance to their current throughput. Cincinnati Gas concludes, therefore, that requiring pipelines to base their rates for the restructured services on their current cost of service and throughput levels is completely illogical.

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The filings in restructuring proceedings are compliance filings to implement the Commission's rulings under NGA Section 5. The requirement that the restructuring filings must be based on the pipeline's currently approved cost of service and throughput provides assurance that the compliance filings reflect only the restructuring required by Order No. 636, and not rate or revenue changes that are not required by the rule. However, as the Commission said in Order No. 636, pipelines may file notices of rate changes under Section 4 of the NGA concurrently with their restructuring filings to reflect changes in costs or throughput, or to seek rate increases due to implementation of the rule, so long as they are not filed in the restructuring proceedings.

6. Incentive regulation

A number of parties requested rehearing with respect to incentive ratemaking. Based upon the Commission's statement "that incentive ratemaking may be a better vehicle than exposure to risk for enhancing pipeline efficiency with respect to transportation costs,"[509] the parties mentioned below assert that the issues of SFV rate design and incentive ratemaking are linked and must be considered together. Certain parties (*e.g.*, AGD, ConEd, NIEP, and Peoples Natural Gas) argue that SFV and incentive ratemaking should be considered together in separate proceedings. Certain other parties (Brooklyn Union and the New York PSC) argue that a pipeline should not be allowed to implement SFV unless it also implements an incentive rate program.

On the other hand, several parties (APGA, Illinois Commerce Commission, Marathon, Natural Gas Clearinghouse,

509. Order No. 636 at p. 30,436.

Phillips, United Distribution Companies, and UGI) argue that incentive ratemaking proposals should not be part of the restructuring proceedings. They maintain that the proceedings will be difficult enough without the implementation of incentive ratemaking as an issue and that the inclusion of this issue will divert attention from the implementation of the requirements of Order No. 636. The parties are also concerned that incentive ratemaking proposals could be used as a bargaining chip by a pipeline to the detriment of its customers.

In Order No. 636, the Commission recognized that:

> pipelines may want to utilize incentive ratemaking proposals as a competitive tool in the restructuring proceedings. Subject to the Commission's action in the final policy statement on incentive regulation, the pipelines may wish to file an incentive rate proposal along with its restructuring compliance filing. Any such incentive ratemaking proposal filed contemporaneously with the restructuring compliance filing should include sufficient detail to demonstrate the effect of the incentive rates on the straight fixed-variable (SFV) and unbundling objectives discussed above. Additionally, any incentive rate proposal must have the full support of the parties to the restructuring proceedings and be consistent with the Commission's final policy statement. (footnote omitted)[510]

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510. Order No. 636 at pp. 30,466-67.

The Commission will not, however, mandate the use of an incentive ratemaking mechanism in conjunction with SFV as requested by Brooklyn Union and the New York PSC because it is not necessary to consider SFV and incentive ratemaking together. While the change to SFV may have some impact on a pipeline's risk, and incentive ratemaking may be a way of encouraging efficiency other than exposure to risk, the Commission found in Order No. 636 that "SFV is but one aspect of risk analysis" and that the appropriate forum for risk analysis is a rate proceeding where all factors affecting risk are examined and the rate of return on equity is established.[511]

7. Triennial rate review

A number of LDCs (*e.g.*, Con Ed, AGD, Illinois Power, Michigan Gas, APGA) and state agencies (*e.g.*, New York PSC, State of Louisiana), and NASUCA argue that pipelines should continue to be subject to the three-year rate review currently required by section 154.303(e) of the Commission's PGA (purchased gas adjustment) regulations.[512] They assert that the Commission did not give any reason for eliminating the requirement. They maintain that since the pipelines still retain monopoly power over the transportation system, a three-year rate review is essential to ensure that a pipeline's transportation, storage and other non-gas rates continue to be just and reasonable.

The Commission will not require pipelines to be subject to a three-year rate review. Under Section 4 of the NGA, the Commission is required to ensure that rate changes filed by a

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511. Order No. 636 at p. 30,437.

512. 18 CFR 154.303(e).

pipeline are just and reasonable. Under Section 5 of the NGA, if the Commission finds a rate to be unjust and unreasonable, after a hearing initiated upon complaint or its own motion, it must set the just and reasonable rate. Thus, the Commission examines the justness and reasonableness of rates under these two scenarios. The three-year review was part of the PGA regulatory scheme — in exchange for the ability to change only one cost element pipelines had to agree to a reexamination of all their costs and rates at three year intervals to assure that gas cost increases were not offset by decreases in other costs. It was not employed only because a pipeline has a monopoly. Since there is no comparable special rate adjustment mechanism here, there is no reason for the three-year review. In the Commission's view the procedures provided under NGA Sections 4 and 5, for ensuring that rates are just and reasonable, should provide sufficient protection to a pipeline's customers under ordinary circumstances.

On a different point, Llano argues that the Commission acted arbitrarily and capriciously in maintaining the three-year rate filing requirement for intrastate pipelines providing NGPA Section 311 transportation while effectively eliminating the requirement for interstate pipelines.

There may or may not be merit to Llano's arguments, but intrastate rates are beyond the scope of this proceeding.

8. Miscellaneous

a. Rates in effect subject to refund when restructuring filings are made

Gas Company of New Mexico requests clarification that if

a pipeline's rates in effect at the time the restructuring compliance filings are made are being collected subject to refund, the post-restructuring collections will also be subject to refund pending resolution of the pipeline's pending rate proceeding.

The Commission grants this clarification.

b. A "reopener" provision in an existing settlement

LILCO states that a current rate settlement between it and one of its pipeline suppliers includes a "reopener" provision that permits throughput increases resulting from restructuring. LILCO seeks clarification that by requiring that new rates be set based on the currently effective total throughput, the Commission did not intend to abrogate LILCO's rights under the settlement to seek an adjustment in transportation rates based on changes in throughput.

Since this is an issue that apparently pertains to only one settlement involving one pipeline, the Commission will not address it in this order. It may be raised in the pipeline's restructuring proceeding.

c. Discovery and procedural disputes

LILCO asserts that it is essential to have a mechanism or procedure in place for resolving disputes that may arise with respect to the exchange of necessary data or information, scheduling issues, and other problems, and recommends that each pipeline's restructuring proceeding be assigned to an administrative law judge. LILCO proposes that the compliance filing be submitted to the judge for an initial finding, after

consideration of comments, of whether it complies with Order No. 636.

Tejas asks the Commission that parties to restructuring proceedings will have full discovery rights in order to verify the appropriateness of pipelines' restructuring proposals. Tejas requests that discovery procedures be available immediately, because access to accurate and complete information will greatly facilitate the settlement process.

The Public Service Company of Colorado[513] also request the right to utilize formal discovery procedures under Rule 401 *et seq.* of the Commission's rules of practice and procedure, and that an administrative law judge be appointed to each restructuring proceeding to resolve any discovery disputes.

On June 24, 1992, the Commission issued an order in this rulemaking proceeding establishing a discovery procedure for restructuring proceedings in response to a motion by Natural Gas Clearinghouse.[514] The Commission directed its staff in the restructuring proceedings to submit data requests to the pipelines to elicit information that parties would need to evaluate restructuring proposals, and required the pipelines to serve answers to those requests on all parties to the restructuring proceeding. The Commission also directed its staff to assist in resolving informally any disputes regarding such data requests, and provided that parties could present unresolved discovery disputes to the Commission after the pipeline has filed its compliance filing. Thus, the Commission has already addressed these rehearing requests.

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513. Public Service Company of Colorado, Western Gas Supply Company, and Cheyenne Light, Fuel and Power Company

514. 59 FERC ¶ 61,351 (1992)

Appendix C

d. Opportunity to develop a record

Western Resources requests that a pipeline's customers have an opportunity make a record on contested items in pipeline restructuring proposals, and suggests the Commission encourage the use of alternative dispute resolution devices and set limited issues for hearing and decision on an expedited basis when such devices are not successful in resolving the issue. Western Resources asserts that pleadings on contested issues will not always provide an adequate record, because they do not afford parties the opportunity to test the merits of other parties' arguments through discovery and cross-examination.

Marathon seeks assurance that parties will be entitled to a trial-type evidentiary proceeding on issues in restructuring proceedings that turn on disputed material facts. Specifically, Marathon questions the Commission's statement in Order No. 636 that restructuring proceedings will not be set for hearing before administrative law judges unless they are consolidated with other proceedings already pending before a judge.[515] Marathon argues that petitioners' statutory due process rights under the NGA will be violated if they are denied the right to develop a record through a trial-type hearing.

The Commission will establish appropriate procedures to resolve contested issues in restructuring proceedings. However, the Commission will not routinely set restructuring proceedings for hearing before administrative law judges. It should be possible in most such proceedings to resolve disputed issues on the basis of adequate records without trial-type hearings. But the Commission will determine whether such a hearing is necessary in a particular restructuring proceeding on the basis of the nature of the disputed issues.

515. Order No. 636 at p. 30,467.

Appendix C

e. Timing of compliance filings by downstream pipelines

Tenneco asserts that it is unreasonable for the Commission to expect downstream pipelines to restructure their services when they do not know what their upstream pipelines' services will look like, and suggest that downstream pipelines have an additional six to eight months to implement their restructuring initiatives. CNG also seeks rehearing of the requirement that downstream pipelines make compliance filings contemporaneously with those of their upstream pipelines.

The Commission denies these requests. While there may be significant details to be worked out in restructuring proceedings, Order No. 636 provides very specific direction on its major features. Downstream pipelines can prepare their compliance filings with confidence that their upstream pipelines (which are subject to Order No. 636) will be required to comply with the same provisions of that order that the downstream pipelines are required to comply with. The Commission will consider any proposals by downstream pipelines to adjust certain provisions of their own restructuring filings in light of restructuring provisions implemented on their upstream pipelines as they are presented, but no basis has been shown for an across-the-board deferral of compliance by downstream pipelines.

f. Requests for exemption from Order No. 636

OkTex asks that Order No. 636 not be applied to it, because it is small (only eight miles of pipe) and provides transportation only. Various other small pipelines and ANR Storage Company (ANR Storage) also seek exemption from Order No. 636. ANR

Storage asserts that it neither sells gas, nor transports it on behalf of others, and that it does not have a blanket transportation certificate under Part 284.

Pipeline-specific requests of this nature should be raised in pleadings in the pipeline's restructuring proceedings. They will not be addressed in this order. The Commission has terminated certain restructuring proceedings on grounds that pipelines were not jurisdictional[516] or had unique characteristics that render the restructuring requirements inapplicable.[517]

g. The Commission's staff in restructuring proceedings

The Public Service Company of Colorado also requests that the Commission's staff be involved in the restructuring proceedings as an active player, and not just as a facilitator. They assert that over the years, many smaller customers of the pipelines have come to rely on the staff's active participation in Commission proceedings as a critical resource.

The Commission's staff is actively involved in restructuring proceedings and will continue to be so, as needed, throughout the course of those proceedings. However, the role of the staff in these proceedings is not the same as that of litigation staff in proceedings set for hearing before an administrative law judge. The staff involved are serving as advisory staff to the Commission are therefore subject to the *ex parte* rules. They

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516. North Penn Gas Company, 59 FERC ¶ 61,258 (1992), Inland Gas Company, Inc., 59 FERC ¶ 61,365 (1992), and Green Canyon Pipe Line Company, 59 FERC ¶ 61,371 (1992).

517. Freeport Interstate Pipeline Company, 59 FERC ¶ 61,378 (1992).

will assist the parties in understanding how to comply with Order No. 636 and will advise the Commission on whether the pipelines and interested parties are implementing Order No. 636 on a timely basis, and whether the filings submitted by the pipelines constitute effective compliance with the Final Rule.

h. Coercive settlement provisions

In Order No. 636, the Commission said it would not tolerate coercive provisions in a pipeline's offer to settle a restructuring proceeding that have the effect of forcing parties to acquiesce in a settlement by threatening the denial of essential services.[518] Marathon argues that such coercive provisions pertaining to transition cost recovery should also be proscribed, citing a decision on a "cosmic" settlement for Tennessee Gas Pipeline Company where the Commission found that transition cost recovery provisions do not pertain to essential services.[519]

As the Commission said in Order No. 636, a party may not be threatened with denial of essential services under restructuring for failure to agree to a settlement offer by the pipeline. However, if a party to a restructuring proceeding does not agree to a pipeline's offer to compromise its contested claim for transition costs, the pipeline may to file to recover the costs it claims, subject to Commission rulings on any challenge to its prudence or protests to eligibility of the costs for recovery as Order No. 636 transition costs. The availability of essential services will not be jeopardized by ongoing proceedings on contested transition cost filings.

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518. Order No. 636 at pp. 30,467-68.

519. Tennessee Gas Pipeline Company, 59 FERC ¶ 61,045 at pp. 61,171-175 (1992).

Appendix C

i. Precedential effect of rulings on restructuring proceedings

Marathon requests that the Commission state that rulings in restructuring proceedings will have no precedential effect, similar to the statement usually made in approving settlements. Otherwise, parties that have an interest in these proceedings would have to intervene in or monitor all of the restructuring proceedings to protect their interests. As an alternative, Marathon suggests that the Commission provide public notice and an opportunity for comment whenever an issue of potentially generic applicability arises in a restructuring proceeding.

Commission rulings on contested issues in restructuring proceedings will have value as precedent, just as Commission rulings on the merits in any other type of proceeding. If a ruling in one restructuring proceeding appears to affect parties in other proceedings in which the same or similar issues are pending, the affected parties are free to argue that the precedent established in another proceeding should not be applied in their case.

X. IMPACT ON PROJECT-FINANCED AND ANGTS PREBUILD PIPELINES

A. Project-financed Pipelines

Ozark objects to the provisions of the new section 284.242 of the Commission's regulations that require pipelines to offer to assign their firm capacity on upstream pipelines to their firm shippers. Because of the terms of its financing arrangement (indenture), Ozark's lenders have the right to approve any other shippers that take on the minimum bill obligations currently

borne by Columbia and Tennessee, and if either of these pipelines is relieved of its liability for its capacity on Ozark without the lenders' approval, Ozark will be in default on the terms of its loan. Thus, Ozark seeks a ruling from the Commission that section 284.242 will not work to allow Columbia or Tennessee to assign their firm capacity on Ozark to another shipper until and unless that shipper has been approved by Ozark's lenders in accordance with the terms of the indenture.[520]

A consortium of banks[521] that provided financing for Kern River, also a project-financed pipeline, seek clarification that shippers under existing firm transportation contracts will not be relieved of their contractual obligations as a result of the capacity reallocation process under Order No. 636 without the pipeline's consent.

The Commission will grant the requested clarification. Assignors of capacity on project-financed pipelines whose loan agreements require creditor approval of substitute shippers are not relieved of liability for assigned capacity, unless the project-financed pipeline agrees to release the assignor from such liability. Thus, if creditor approval of the new shipper cannot be secured, the assigning shipper must serve as a guarantor of payments under the existing contract even though another shipper is assigned the capacity.

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520. Other pipelines make this same request: Trailblazer Pipeline Company, Northern Border Pipeline Company (Northern Border), Overthrust Pipeline Company (Overthrust), U-T Offshore System (U-TOS), and Wyoming Interstate Company (Wyoming Interstate).

521. Barclays Bank, PLC, Canadian Imperial Bank of Commerce, Credit Lyonnais, and the Fuji Bank, Ltd. (Barclays).

Appendix C

B. ANGTS prebuild pipelines

Foothills Pipe Lines, Ltd.(Foothills), a Canadian pipeline, urges the Commission to exempt the ANGTS prebuildproject from Order No. 636 to the extent necessary to ensure that there will be no assignment, release, or reallocation of prebuild pipeline capacity without the prior agreement of all parties to the relevant prebuild import and resale contracts. Foothills is concerned that under section 284.242 of the Commission's regulations, as promulgated in Order No. 636, Northern Natural and Panhandle Eastern Pipeline Company (Panhandle), both of whom are major purchasers of Canadian gas for transport through Northern Border, a component of the ANGTS prebuild project, could be required to assign their capacity on Northern Border to their firm customers, thus arguably excusing Northern Natural and Panhandle from purchasing Canadian gas from Northwest Alaskan Pipeline Company and, indirectly, from Pan-Alberta Gas, Ltd. (Pan-Alberta).

Foothills is also concerned that section 284.14(e) of the new regulations would permit Pacific Interstate Transmission Company an opportunity during the restructuring proceedings to relinquish its prebuild capacity on PGT, Northwest, and El Paso, and permit Pan-Alberta Gas (U.S.) to relinquish its prebuild capacity on Northern Border. Finally, Foothills notes that the capacity release program under new section 284.243 would provide buyers of prebuild gas ongoing opportunities to release their prebuild capacity to other shippers. Foothills asserts that in each of these situations, there could be a decoupling of the prebuild transportation capacity from the prebuild gas purchase obligations which, together, provide the revenues to defray the cost of the Canadian prebuild investment. The Canadian prebuild investment includes not only the Foothills

interprovincial pipeline facilities, but also intraprovincial pipeline facilities and substantial gas producing facilities. According to Foothills, permitting pipelines grounds to default on their purchase obligations to Canadian producers would violate various time-honored commitments by the Commission, the U.S.-Canadian Agreement on Principles, and Section 9(d) of the Alaska Natural Gas Transportation Act.[522] Foothills also expresses concern about the possibility that Northern Natural and Panhandle will lose needed capacity on their own systems through the unbundling and conversion process under sections 284.284 and 284.8(a)(4) of the new regulations.

Foothills' and Pan Alberta's concerns about the rule's effect on the prebuild shippers' purchase obligations are misplaced. The rule does not alter contracts between shippers and their suppliers. Moreover, nothing in the rule is intended to disturb the United States government's commitment to the ANGTS prebuild. Foothills' concern about Panhandle and Northern Natural's capacity can be addressed in those pipelines' restructuring proceedings.

XI. EFFECTIVE DATE

The amendments to the Commission's regulations adopted in this order on rehearing will become effective [insert date 30 days after publication of this order in the *Federal Register*].

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522. Pan Alberta makes very similar arguments in its request for rehearing.

Appendix C

List of subjects in 18 CFR Part 284
Continental shelf
Natural Gas
Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission denies rehearing in part, grants rehearing in part, clarifies Order No. 636 as described above, and amends Part 284, Chapter I, Title 18, *Code of Federal Regulations*, as set forth below.

By the Commission. Commissioner Moler dissented in part with a separate statement attached. Commissioner Terzic concurred with a separate statement attached.

(SEAL)

Lois D. Cashell,
Secretary.

Appendix C

Part 284 — CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

1. The authority citation for Part 284 is revised to read as follows:

Authority: 15 U.S.C. 717-717w; 15 U.S.C. 3301-3432; 43 U.S.C. 1331-1356; 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR, 1978 Comp., p. 142

2. In § 284.14, paragraph (b)(3)(iii) is redesignated as paragraph (b)(3)(v), new paragraphs (b)(3)(iii) and (iv) are added, and paragraph (e) is revised to read as follows:

§ 284.14 Provisions governing pipeline restructuring.

* * * * *

(b) * * *

(3) * * *

(iii) The compliance filing must include a cost-based sales rate for small customers that are entitled to purchase gas under a pipeline's one-part, imputed-load-factor rate schedule on the effective date of a pipeline's blanket certificate under § 284.284, to apply for a period of one year from that date.

(iv) (A) Except as provided in paragraph (b)(3)(iv)(B) of this section, a pipeline that offered a sales or transportation service to small customers with a one-part volumetric rate at an imputed load factor on May 18, 1992, must include tariff

provisions in its compliance filing to charge a rate for firm transportation services under § 284.8 on the same basis and under the same eligibility criteria as the small customer sales or transportation rate under the pipeline's last-approved tariff provisions for those services.

(B) A pipeline may increase the permissible daily service levels for the small customer transportation rate up to 10,000 Mcf or Dth per day. A customer that receives service under its small customer transportation rate may not ship gas under any interruptible transportation rate schedule available from the pipeline or ship gas as a replacement shipper on the pipeline under § 284.243, unless the customer has exhausted its daily levels of firm transportation from the pipeline. A pipeline's firm transportation service for small customers may not contain service conditions more restrictive than the restrictions permitted by paragraph (b)(3)(iv) of this section.

* * * * *

(e) *Adjustments to firm transportation service; automatic abandonment.* (1) Any firm shipper on a pipeline subject to this section must give notice to the pipeline during the pipeline's restructuring proceeding whether the shipper wants to retain, reduce, or terminate its contractual rights to firm transportation service.

(2) Except as provided in paragraph (e)(4) of this section, any firm shipper may reduce or terminate its contractual rights and obligations for firm transportation service subject to this section, if the shipper gives notice of its desire to reduce or terminate service under paragraph (e)(1) of this section, and

(i) the pipeline receives an offer for the available firm transportation service from a creditworthy shipper that is equal to or greater than the rate the existing firm shipper is contractually obligated to pay, up to the maximum rate, or

(ii) the pipeline agrees to the reduction or termination of the existing firm shippers' contractual obligations.

(3) Except as provided in paragraph (e)(4) of this section, a pipeline subject to this section may abandon firm transportation service under a contract with a firm shipper:

(i) to the extent the shipper reduces or terminates its contractual obligations under paragraph (e)(2) of this section, or

(ii) if, during the pipeline's restructuring proceeding, another creditworthy shipper offers a higher rate for the service than the existing firm shipper, up to the maximum rate, which the existing shipper declines to match, and the pipeline is not contractually precluded from charging the higher rate to the existing firm shipper.

(4) Paragraphs (e)(1)-(3) of this section do not apply to the firm transportation service provided for a downstream pipeline subject to Subpart B or G of this part on an upstream pipeline subject to Subpart B or G of this part, unless the existing firm customers of the downstream pipeline concur in the decision of the downstream pipeline to reduce or terminate its firm transportation service on the upstream pipeline.

(5) The authority to abandon service under this paragraph is effective:

(i) on the effective date of the contract to provide the service to another shipper, or

(ii) on the effective date of the pipeline's agreement to the reduction or termination of the existing firm shipper's contractual obligations.

3. In § 284.221, the introductory text of paragraph (d)(2) is revised by removing the words "more than one year" and adding, in their place, the words "one year or more", and paragraph (d)(2)(ii) is revised by removing the words "those terms" at the end of the paragraph and adding, in their place, the words "the terms of any such offer".

4. In § 284.242, the first sentence is revised to read as follows:

§ 284.242 ***Assignment of firm capacity on upstream pipelines.***

An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on all upstream pipelines, whether the firm capacity is authorized under Part 284 or Part 157. * * *

5. In § 284.243, paragraphs (c) and (d) are revised, and a new paragraph (h) is added, to read as follows:

§ 284.243 ***Release of firm capacity on interstate pipelines.***

* * * * *

(c) Except as provided in paragraph (h) of this section, a

firm shipper that wants to release any or all of its firm capacity must notify the pipeline of the terms and conditions under which the shipper will release its capacity. The firm shipper must also notify the pipeline of any replacement shipper designated to obtain the released capacity under the terms and conditions specified by the firm shipper.

(d) The pipeline must provide notice of offers to release or to purchase capacity, the terms and conditions of such offers, and the name of any replacement shipper designated in paragraph (b) of this section, on an electronic bulletin board, for a reasonable period.

* * * * *

(h) (1) A release of capacity by a firm shipper to a replacement shipper for any period of less than one calendar month need not comply with the notification and bidding requirements of paragraphs (c) through (e) of this section. A release under this paragraph may not exceed the maximum rate. Notice of a firm release under this paragraph must be provided on the pipeline's electronic bulletin board as soon as possible, but not later than forty-eight hours, after the release transaction commences.

(2) A firm shipper may not rollover, extend, or in any way continue a release under this paragraph without complying with the requirements of paragraphs (c) through (e) of this section, and may not re-release to the same replacement shipper under this paragraph until thirty days after the first release period has ended.

6. In § 284.282, a new paragraph (d) is added to read as follows:

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§ 284.282 *Definitions.*

* * * * *

(d) *Small customer* is a customer that purchases gas from a pipeline under the pipeline's one-part imputed load factor rate schedule on the effective date of the blanket certificate.

7. In § 284.284, a new paragraph (e) is added to read as follows:

§ 284.284 *Blanket certificates for unbundled sales services.*

* * * * *

(e) *Small customer cost-based rate.* A pipeline that provided bundled sales service to a small customer before the effective date of the blanket certificate granted in paragraph (a) of this section is required to offer a sales service to that customer at a cost-based rate for one year from the effective date of the certificate. The obligation to sell at the cost-based rate expires one year after the effective date of the certificate.

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APPENDIX

Alphabetized Listing of Requests for Rehearing of Order No. 636

Alabama Gas Corporation and
Clarke-Mobile Counties Gas District
Mississippi Valley Gas Company
Mobile Gas Service Corporation
North Carolina Natural Gas Corporation
Public Service Company of North Carolina, Inc.
Willmut Gas and Oil Company (Alabama Gas)

Alabama-Tennessee Natural Gas Company (Alabama-Tennessee)

American Paper Institute, Inc. (American Paper Institute)

American Public Gas Association (APGA)

Amoco Production Company (Amoco)

ANR Pipeline Company (Correction filed 5-13-92) (ANR)

ANR Storage Company (ANR Storage)

Arizona Electric Power Cooperative, Inc. (Arizona Electric)

Arizona Direct Customers

Arkla, Inc. (Arkla)

Associated Gas Distributors (Request for clarification filed 5-15-92) (AGD)

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Atlanta Gas Light Company and
Chattanooga Gas Company (Atlanta Gas)

Baltimore Gas and Electric Company (BG&E)

Barclays Bank, PLC and
Canadian Imperial Bank of Commerce
Credit Lyonnais
Fuji Bank, Ltd. (Barclays)

Brooklyn Union Gas Company (Brooklyn Union)

Brooklyn Union Gas Company
Consolidated Edison Company of New York, Inc.,
Public Service Electric and Gas Company (Joint Request)

Brymore Energy, Inc. (Brymore)

Carnegie Natural Gas Company (Carnegie)

Cascade Natural Gas Corporation
and Washington Water Power Company (Cascade)

Centra Gas Manitoba, Inc. (Centra Gas)

Cincinnati Gas & Electric Company
The Union Light, Heat and Power Company
Lawrenceburg Gas Company
Mountaineer Gas Company (Substitute copy with corrections filed 5-11-92) (Cincinnati Gas)

Citizen Action

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Citizens Gas and Coke Utility (Citizens Gas)

City Gas Company (City Gas)

City of Colorado Springs, Colorado (Colorado Springs)

City of Hamilton!, Ohio (Hamilton)

City of Vicksburg (Vicksburg)

CNG LDCs (East Ohio Gas Company, River Gas Company, West Ohio Gas Company Peoples Natural Gas Company, Virginia Natural Gas, Inc., and Hope Gas, Inc.)

CNG Transmission Corporation (CNG)

Coalition Against Straight Fixed Variable (Coalition)

Colorado Interstate Gas Company (CIG)

Columbia Gas Distribution Companies

Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company (Columbia)

Consolidated Edison Company of New York, Inc. (Correction filed 5-13-92) (ConEd)

Delta Pipeline Company (Delta)

Department of the Interior,
Minerals Management Service (MMS)

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Destec Energy, Inc. (Destec)

Edison Electric Institute (Edison Electric)

Elizabethtown Gas Company (Elizabethtown)

El Paso Natural Gas Company (El Paso)

Equitrans, Inc. (Equitrans)

Fertilizer Institute

Florida Power and Light Company (Florida Power)

Foothills Pipe Lines Ltd. (Foothills)

Fort Pierce Utilities Authority and
City of Vero Beach (Fort Pierce)

Fuel Managers Association

Gas Company of New Mexico

Great Lakes Gas Transmission Limited Partnership (Great Lakes)

Hadson Gas Systems, Inc. (Corrected pages filed 5-12-92) (Hadson)

High Island Offshore System (HIOS)

Illinois Commerce Commission

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Illinois Power Company and
Northern States Power Companies (Illinois Power)

Independent Petroleum Association of America and
Cooperating Associations (IPAA)

Indiana Gas Company, Inc. (Indiana Gas)

Indicated Shippers

Industrial Gas Users Conference

Industrial Groups (Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufacturers Association, and California League of Food Processors)

Interstate Natural Gas Association of America (INGAA)

Kansas Corporation Commission (KCC)

Kentucky Ohio Gas Company (Kentucky Ohio)

Kern River Gas Transmission Company (Kern River)

K N Energy, Inc. (K N Energy)

Laclede Gas Company (Laclede)

Llano, Inc. (Llano)

Long Island Lighting Company (LILCO)

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Marathon Oil Company (Letter filed 5-11-92) (Marathon)

Maryland People's Counsel

Memphis Light, Gas and Water (Memphis Light)

Michigan Gas Utilities Division of
Utilicorp United Inc. (Michigan Gas)

Midcon Marketing Corporation (Midcon Marketing)

Midland Cogeneration Venture Limited Partnership (Midland Cogeneration)

Mobil Natural Gas Inc. (Mobil)

Municipal Gas Authority of Georgia

National Association of Gas Consumers

National Association of State Utility Consumers Advocates (NASUCA)

National Association of Regulatory Utility
Commissioners, Inc. (NARUC)

National Fuel Gas Supply Corporation (National Fuel)

National Independent Energy Producers (NIEP)

Natural Gas Clearinghouse

Natural Gas Pipeline Company of America (Natural)

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Natural Gas Supply Association/Indicated Producers (NGSA)

New England Gas Distributors

New England Power Company (New England Power)

New England Power Company in support of
Northeast Energy Associates, *et al.*

New Jersey Natural Gas Company (New Jersey Natural)

New York State Electric and Gas Corporation (NYSE&G)

Northeast Energy Associates and
North Jersey Energy Associates (Northeast Energy)

Northern Border Pipeline Company (Northern Border)

Northern Distributor Group

Northern Illinois Gas Company and
Peoples Gas Light and Coke Company
North Shore Gas Company (Northern Illinois Gas)

Northern Indiana Public Service Company (Northern Indiana)

Northern Natural Gas Company (Northern Natural)

Northwest Natural Gas Company (Northwest Natural)

Northwest Pipeline Corporation (Northwest)

Official Committee of Unsecured Creditors of the Columbia Gas
Transmission Corporation (Columbia Unsecured Creditors)

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OkTex Pipeline Company (OkTex)

O&R Energy, Inc. (O&R Energy)

Overthrust Pipeline Company (Overthrust)

Ozark Gas Transmission System (Ozark)

Pacific Gas and Electric Company (PG&E)

Pacific Gas Transmission Company (PGT)

Pan-Alberta Gas Ltd. (Pan Alberta)

PEC Pipeline Group (PEC Group)

Pennsylvania Public Utility Commission (Pennsylvania PUC)

Peoples Gas System, Inc. (Peoples Gas)

Peoples Natural Gas Company (Peoples Natural Gas)

Philadelphia Electric Company (Philadelphia Electric)

Phillips Petroleum Company and
Phillips Gas Marketing Company
GPM Gas Corporation (Phillips)

Potomac Electric Power Company (PEPCO)

Public Service Commission of the Commonwealth of Kentucky
(Kentucky PSC)

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Public Utilities Commission of the State of California (CPUC)

Public Service Commission of the State of New York (New York PSC)

Public Service Company of Colorado and Western Gas Supply Company Cheyenne Light, Fuel and Power Company (Public Service Company of Colorado)

Public Service Electric and Gas Company (PSE&G)

Questar Pipeline Company (Questar)

Reynolds Metal Company (Reynolds)

Rochester Gas and Electric Corporation (Rochester Gas)

South Carolina Pipeline Corporation (South Carolina Pipeline)

Southern California Edison Company (SoCal Edison)

Southern California Gas Company (SoCal Gas)

Southern Indiana Gas and Electric Company (Southern Indiana)

Southern Natural Gas Company (Southern)

Southwest Gas Corporation (Southwest Gas)

Spot Market Corporation of The State of Texas (Spot Market Corporation)

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State of Louisiana

State of Michigan and Michigan Public Service Commission (State of Michigan)

State Regulatory Commissions (Iowa, Missouri, and Wisconsin) (Iowa, Missouri and Wisconsin Commissions)

Tejas Power Corporation (Supplemental filed 5-20-92) (Tejas)

Tenneco Gas (Tenneco)

Tennessee Small General Service Customer Group
Columbia Small Customer Group (Tennessee and Columbia Small Customers)

Texas Gas Transmission Corporation (Texas Gas)

Three State Agencies (Montana Consumer Counsel, South Dakota Public Utilities Commission, and the Montana Public Service Commission) (Montana Agencies and South Dakota Commission)

Trailblazer Pipeline Company (Trailblazer)

Transcontinental Gas Pipe Line Corporation (Transco)

UGI Utilities, Inc. (UGI)

United Distribution Companies

United Gas Pipe Line Company (United)

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U-T Offshore System (UTOS)

Virginia Electric Power Company (VEPCO)

Washington Gas Light Company (Washington Gas)

Western Resources, Inc. (Western Resources)

Wisconsin Distributor Group

Wyoming-California Pipeline Company (WyCal)

Wyoming Interstate Company, Ltd. (Wyoming Interstate)

Appendix C

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-002

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-068

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued August 3, 1992)

MOLER, Commissioner, *dissenting in part*:

I am pleased that in Order No. 636-A we have adopted many changes in response to concerns about requiring straight fixed variable rate design. However, I must dissent from two aspects of the order on rehearing: the level of the transition costs allocated to interruptible customers, and the 20-year contract term "cap" for the right of first refusal.

Order No. 636-A rests on the rationale that the current regulatory climate is unworkable and results in "anticompetitive consequences for *all* segments of the industry and consumers."[1] Thus, the rule is necessary to create "a modern, viable natural gas industry specifically fashioned to the needs of *all* gas consumers and the Nation . . . ."[2] Because the rule is aimed at

1. Order No. 636-A, slip op. at 35 (emphasis added).

2. *Id.* at 2 (emphasis added).

providing benefits to *all* segments of the industry,[3] I believe that *all* segments of the industry should bear an equitable share of the transition costs that will inevitably occur as a result of this rule. Simply put, I do not believe the rule meets that test.

Some state commissions suggested a volumetric surcharge for the recovery of gas supply realignment costs.[4] I believe that adopting their suggestion would have been wiser than the "10 percent solution" adopted by the majority. That approach, a 10 percent allocation of gas supply realignment costs to interruptible customers, does not reflect the benefit that these customers are receiving from the industry restructuring. The figures show that at least half of the pipeline deliveries to market are under IT rate schedules.[5] To require these customers to now bear only 10 percent of the gas supply realignment costs (and these do not encompass all transition costs) is not equitable.[6]

I have come to the conclusion that a volumetric surcharge, with a true-up mechanism, most fairly reflects an equitable

3. *Id.* at 35, 37-38, 40-41.

4. *E.g.*, CPUC; Illinois; Iowa, Missouri and Wisconsin; State of Michigan; and New York PSC.

5. Order No. 636-A, slip op. at 30, n.41.

6. I must point out that, while the 10 percent cost allocation mechanism to IT service provides for some kind of "true-up" mechanism (Order No. 636-A at 5, n.5 and 353), the mechanism is not tied to IT service. Thus, while 10 percent of the costs could be allocated to IT service, if only 5 percent are collected (say over the next 2 years) there is nothing to prevent the pipeline from allocating the remaining 5 percent to firm service in the future. While I support a true-up mechanism to prevent absorption of costs by the pipeline, it should be tied to the service that the costs are allocated to.

sharing of the gas supply realignment costs that will result from the rule among all segments of the industry who will benefit from the rule. I realize that the volumetric surcharge somewhat undercuts the Commission's goal of lowering usage charges, but I find convincing the California Public Utilities Commission's argument that even the 75 percent volumetric surcharge presently in place under Order Nos. 500 and 528 for take-or-pay costs has resulted in only moderate customer impacts (4¢/dth for El Paso and 1¢/dth for Transwestern).[7] If my colleagues are right, most of the costs of contract reformation are behind us. Therefore, gas supply realignment costs should not approach the level of take-or-pay costs under Order Nos. 500 and 528. Thus, I believe that a 25 percent volumetric surcharge on all throughput volumes, with a true-up mechanism, best achieves the goal of spreading gas supply realignment costs among all segments of the industry.

My second problem is the majority's decision to unnecessarily hobble LDCs in exercising their right of first refusal. In Order No. 636, the Commission adopted a requirement that the existing customer match the contract term, without specifying the length of term it must match, as well as the price.[8] In Order No. 636-A, the majority has determined that a 20-year contract term is an appropriate cap on the contract term because it is the "traditional length of long-term contracts," and several recent contracts have been for 20-year terms.[9]

I cannot agree to such a blatantly anti-LDC rule. Almost all

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7. Order No. 636-A, slip op. at 351.

8. Order No. 636 at 30,449-450.

9. Order No. 636-A, slip op. at 306.

of the LDCs requested that the contract term be capped at 5 years because bidders could take capacity away from them by offering a longer contract term, thus endangering their ability to meet their service obligation. The record simply does not support a 20-year term. I believe that basing the selection of the 20-year term upon an "historical" basis is ludicrous — the entire thrust of the rule is toward the future, not the past. Finally, I find that using as precedent cases involving contracts for *new* pipeline capacity not to be compelling support for the 20-year term that *existing* capacity holders on *existing* pipelines must match.

Any generic regulation must, to a certain degree, be procrustean. Here, though, by providing that only 10 percent of the gas supply realignment costs be borne by IT customers, the majority cuts too short and by inflicting a 20-year contract term cap on the right of first refusal, the majority stretches too long. Therefore, I must dissent on these two aspects of Order 636-A.

Elizabeth Anne Moler
Commissioner

Appendix C

Docket No. RM91-11-002

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-068

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued August 3, 1992)

TERZIC, Commissioner, *concurring*:

I must concur in this extensive rehearing order. While I believe that the country needs the certainty inherent in this major and unprecedented order, I continue to believe that the ultimate success of the Order No. 636 process will depend on the level of flexibility the Commission and the staff on its behalf allow in implementation of the substantive provisions of this order. In this regard I reiterate my belief that many of the criticisms leveled at the rule should have been, and could have been, addressed by allowing for more flexibility in the rule.

While the rule adopts some flexibility with respect to historically sensitive issues, such as small customer gas sales and rates, it rigidly continues to preclude such requested options as: a minimal level of residual bundled sales service and use of rate designs other than SFV for cost allocation and billing purposes. Further, the rule attempts to decide issues that I think should be left to individual restructuring proceedings (*e.g.*, whether bids for released capacity should be capped at a given number of years), where there is superior expertise and factual

basis for a decision as to the specifics. This point comports with the rule's too rigid one-size-fits-all aspects. This I find surprising from the Commission, which should have a lesser rather than greater affinity for "command and control" type regulation, which this rule imitates in its level of detail for some treatments.

Thus, while the rule adopts what can be characterized as an opportunity for flexibility, with respect to a minuscule percentage of the industry's load, it retains inflexibility with respect to major parts of the pipeline industry's operations. The decisions here achieve a level of precision that may leave little left to negotiate in the restructuring process and may, in fact, be wrong for the particular system and its customers.

In sum, a major problem with this rehearing order and its predecessor lies not so much in the substance of the calls, but in a nagging belief that, based on the open meeting discussions and treatment of the companion orders, the 636 orders will be implemented by this Commission and its staff in a procrustean manner. I fear that there may be little room left for true negotiation in the restructuring process. If there is some room left to maneuver, I am not optimistic that this Commission will sanction the results of such negotiations, if they in any way deviate from the particular treatments contemplated and specified in the 636-A order.

I suspect that despite the nods to flexibility in the rehearing order and the rhetoric accompanying the voting process, little room exists to accommodate such things as changes in rate design and other treatments based on pipeline system operational differences and customer wishes.

I hope I am wrong. The situation can possibly be remedied

in practice, where it has not been in this document. That is why I can concur. Today's accompanying vote on the ANR settlement in Docket No. RS92-1-001 gives me cause to wonder. It should give the industry and state regulators cause to wonder too. However, dénouement of the Order No. 636 saga is a long way off. Thus, ever optimistic, I will continue to push for flexibility in implementation, keeping in mind that, flexibility in regulation, in this case, is in the public interest.

Branko Terzic
Commissioner

APPENDIX D — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636-B", *ORDER ON REH'G*, 61 F.E.R.C. ¶ 61,272 (1992)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martin L. Allday, Chairman; Charles A. Trabandt, Elizabeth Anne Moler, Jerry J. Langdon and Branko Terzic.

Docket No. RM91-11-004

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-069

Regulation of Natural Gas Pipelines) After Partial Wellhead Decontrol

I. INTRODUCTION

On August 3, 1992, the Federal Energy Regulatory Commission issued Order No. 636-A in which it denied rehearing in part, granted rehearing in part, and clarified Order No. 636.[1] Order No. 636, as modified by Order No. 636-A,

1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the (Cont'd)

restructured the regulation of interstate natural gas pipeline services in order to create a natural gas industry which will provide all gas consumers and the Nation in the long-term with an adequate and reliable supply of clean and abundant natural gas at reasonable prices.

In Order No. 636-A, the Commission largely upheld the regulations adopted in and requirements of Order No. 636. The Commission did, however, make a number of changes to Order No. 636 in response to the rehearing and clarification requests. The Commission has received over eighty petitions for rehearing or clarification or both of Order No. 636-A.[2] The petitioners reargue issues on which rehearing was denied in Order No. 636, challenge changes made to Order No. 636 by Order No. 636-A, and raise some new issues with respect to details of various aspects of Order Nos. 636 and 636-A.

The main issues raised by petitioners are as follows. First, they argue that the Commission erred in denying shippers receiving transportation service under individual or transaction specific Natural Gas Act (NGA) section 7(c) certificates the right to release capacity under section 284.243 of the Commission's regulations and to have the same rights to flexible receipt and delivery points as Part 284 shippers. Second, petitioners oppose

(Cont'd)
Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 FR 13267 (April 16, 1992), III FERC Stats. & Regs. Preambles ¶ 30,939 (April 8, 1992) (Order No. 636); *order on reh'g*, Order No. 636-A, 57 FR 36128 (August 12, 1992), III FERC Stats. & Regs. Preambles ¶ 30,950 (August 3, 1992).

2. See the Appendix for a list of the parties seeking rehearing or clarification or both. Petitioners will be referred to by the abbreviations indicated in the Appendix.

the Commission's requirement that pipelines maintain their one-part volumetric rates computed at an imputed load factor to determine the transportation rates for small customers. Third, petitioners maintain that the Commission erred in requiring pipelines to adopt measures to avoid significant cost shifts that may result from the adoption of the straight fixed variable (SFV) method of cost classification, allocation, and rate design. Fourth, petitioners argue that the Commission should have used a period less than 20 years as the contract term cap that must be matched by a customer exercising its right of first refusal upon expiration of its contract. Fifth, petitioners contend that the Commission erred in requiring pipelines to recover 10 percent of their gas supply realignment costs from their Part 284 interruptible transportation service.

As discussed below, this order denies rehearing and clarifies Order Nos. 636 and 636-A. Hence, no further petitions for rehearing will be entertained and the instant rule is fully ripe for judicial review.

II. LEGAL BASIS AND RATIONALE FOR UNBUNDLING

This part addresses the rehearing requests with respect to the Commission's legal basis and rationale in adopting Order Nos. 636 and 636-A.

A. The Legal Basis

1. Natural Gas Act Authority

In Order Nos. 636 and 636-A, the Commission concluded that it had authority under NGA section 5 to alter a pipeline's contractual terms and conditions of service and that it had not

unlawfully revoked or modified any certificates of public convenience and necessity under NGA section 7. The Commission found that "section 7 cannot be read so narrowly as to permanently prevent the Commission from changing the terms and conditions under which a pipeline provides service, especially when the pipeline's obligation to serve and the LDC's entitlement under the certificate remain intact."[3]

Cincinnati Gas argues that an analysis of the individual elements of Order No. 636-A reveals that the rule does not preserve the pipelines' existing service obligation. It contends that this is so because the new combination of unbundled sales service and no-notice transportation service is not equal to the bundled, city-gate, firm sales service. Cincinnati Gas complains that, under the new combination of services, LDCs, rather than the pipelines, will be responsible for and bear the risk of supplying their gas for the no-notice transportation service. As an example, Cincinnati Gas states its concern that the pipeline and other gas suppliers will subject it to "output" agreements, under which a failure of supply service will merely reduce the contracts' take obligation. Hence, it maintains that it will not be insulated, as it is now, from the risk of obtaining gas supplies to minimize the risks associated with the loss or reduction of production from particular wells. It further contends that the concept of borrowing gas has not been shown to be a viable option for securing gas supplies for firm service. In a similar vein, Cincinnati Gas contends that the conditions attached to no-notice transportation, *e.g.*, imbalance penalties and operational flow orders, show that is inferior to bundled, city-gate, firm sales service. In addition, Cincinnati Gas maintains that a pipeline can free itself from its certificated sales service obligation by merely making an uncompetitive offer to the LDC.

3. Order No. 636-A at p. 30,530.

Appendix D

The Commission adheres to its discussion and conclusion in Order Nos. 636 and 636-A that it has acted within its authority under NGA sections 4(b) and 5 to prevent undue discrimination by altering the pipelines' contractual terms and conditions of service to remedy the unduly discriminatory and anticompetitive structure of the pipeline industry. The Commission rejects Cincinnati Gas's argument that the Commission's action does not comport with NGA section 7.[4] In short, the Commission concludes that the instant rule, in unbundling pipeline sales and transportation services, effects no abandonment of service to Cincinnati Gas or to any other pipeline customer. The Commission amplifies its discussion in Order Nos. 636 and 636-A as follows.

The Commission finds that Cincinnati Gas has presented no reasons to persuade the Commission that it will suffer any diminution in service. At the outset, the pipeline continues to be obligated to deliver gas on a no-notice basis to customers receiving no-notice delivery under bundled, city-gate, firm sales service on May 18, 1992. It is true that the Commission has changed the terms and conditions of service and thereby subjected pipeline customers to more responsibilities, duties, and risks. However, the Commission specifically found that those terms and conditions are necessary and reasonable operational mechanisms for implementing the Commission's remedies to eliminate the anticompetitive effect of the current

4. The Commission has the authority under NGA section 4(b) to prevent undue discrimination among pipeline customers. The Commission may invoke that section, as it did here (Order No. 636 at p. 30,405), to deal with discrimination between pipeline services whether or not it could invoke section 7 for that purpose. FPC v. Louisiana Power & Light Co., 406 U.S. 621, 646 (1972) ("Since § 4(b) deals with `service,' the FPC may invoke it to deal with curtailment programs, whether or not it could also invoke § 7 for that purpose.").

regulatory environment and pipeline services on all segments of the natural gas industry.

It is axiomatic that the consumer of any commodity should be responsible for its purchase and use. That is equally applicable here, where gas buyers will have meaningful access to a national and competitive wellhead gas market. Indeed, because the unbundling remedy requires that sales and transportation be provided separately shippers must take the initiative in obtaining gas and therefore bear the responsibilities and risks of obtaining supply. In addition, this shifting of risk is not unreasonable when, as fully discussed in Order No. 636, the pipelines (and ultimately consumers) were disadvantaged by maintaining gas supplies for sale at their WACOG to LDCs when the supplies were needed by the LDCs only as a peaking source supplement to other cheaper gas supply sources. Other terms and conditions of service are necessary to maintain the operational integrity of the pipeline system because the pipeline cannot sell gas at the city gate. This means that the pipeline must rely in the main on the shippers to supply the gas needed to keep the pipeline in balance and capable of making the necessary deliveries. Hence, imbalance penalties and operational flow orders are intimately connected with the pipeline's performance of its transportation service for shippers.[5]

To conclude, the Commission believes that through such measures, the no-notice transportation service will prove as reliable as the no-notice aspect of bundled, city-gate, firm sales

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5. Cincinnati Gas believes that pipelines will use operational flow orders to interrupt its supply of gas needed for no-notice transportation service. The Commission views operational flow orders as a vehicle for providing, not interrupting, no-notice service and will consider opposition to particular pipeline operational flow order mechanisms in the compliance filing orders.

service. The Commission merely suggested the concept of gas borrowing as a possible tool to aid in the cooperative effort to secure no-notice service. The Commission does not view the borrowing of gas as the only tool for ensuring no-notice service.

LDCs, such as Cincinnati Gas, should be able to negotiate gas purchase contracts with reasonable terms (such as output clauses or gas supply warranties) and prices in the competitive gas market. The mere possibility, unsupported by the rulemaking record, that pipelines will make uncompetitive offers does not invalidate the Commission's ability to act within its NGA section 5 authority. The Commission has no reason to believe that any pipeline will do that or, more importantly, even if a pipeline made such an uncompetitive offer, that any customer will be unable to find adequate, competitively priced supplies from other sources. With the expected enhanced quality of transportation brought about by Order No. 636, there is no reason to expect a diminution in service to any customer. Indeed, as noted, the Commission expects it would be as reliable. Cincinnati Gas has not contended that it, in fact, faces the prospect of a diminution in aggregate service. In fact, Cincinnati Gas now has more options from which to choose from than ever before. Cincinnati Gas complains that it, like other LDCs, is no longer insulated from the risks associated with buying gas in a competitive market. The Commission sees no harm to Cincinnati Gas from acquiring gas in a competitive market. The Commission concludes that the instant rule effects no abandonment of service to Cincinnati Gas or any other pipeline customer by unbundling pipeline sales and transportation services.

There is a possible abandonment of service in connection with the pipeline's obligation to serve under the blanket sales

certificate granted by Subpart J of Part 284. Effective on the effective date of that certificate, section 284.14(d) of the regulations provides for abandonment of pipeline sales if a gas purchaser exercises its right to reduce or terminate its right to purchase gas from a pipeline or if the purchaser refuses to pay the rate the pipeline offers for unbundled gas sales. However, this will result from the operation of the purchasers' decisions under the regulation — not from a generic section 7 finding. The Commission found these abandonment authorizations to be in the present or future public convenience or necessity as part of the transition to pipeline sales under the blanket sales certificates, because they will enable the pipelines and gas purchasers to structure their relationship in light of the market for natural gas.[6] As stated by Congress in section 202 of the Energy Policy Act of 1992: "It is the sense of the Congress that natural gas consumers and producers, and the national economy, are best served by a competitive natural gas wellhead market."[7]

2. Past Precedent

Cincinnati Gas argues that past Commission precedent indicates that the Commission must act under NGA section 7 to accomplish the proposed restructuring. It states that the Commission has required pipelines to apply for certificates under NGA section 7 in order to restructure their services and institute gas inventory charge (GIC) mechanisms[8] and to transport gas

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6. See Order No. 636 at p. 30,452-55.

7. Pub. L. No. 102-486, 106 Stat. 2776 (1992).

8. *E.g.*, Natural Gas Pipeline Co., 41 FERC ¶ 61,358 at pp. 61,972-73 (1972), Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 62,083 (1988), and Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364 (1989).

to an existing shipper at new delivery points.[9] The Commission has acted consistently with the cited cases. The essential aspects of those cases were (1) the fact that the pipeline's customers had to consent to the abandonment of service linked to releasing the pipeline from its obligation to supply gas above a customer's nominated levels[10] and (2) the need to act prospectively with respect to an interrelated package of proposals.[11] Here, the Commission, by operation of the rule, is: (1) providing for abandonment of reduced or terminated customer purchase obligations (section 284.14(d)), (2) issuing each Part 284 pipeline a blanket sales certificate (under Subpart J of Part 284), and (3) acting prospectively under NGA section 5 to avoid a segmented approach. There is therefore no inconsistency with those cases.

The Commission also concludes that Cincinnati Gas's argument that the case requires a certificate to change delivery points is irrelevant. This is because the Commission did not, as a policy matter, permit flexible delivery points as a term and condition of transportation service until Order No. 636 modified that policy for Part 284 pipelines.[12]

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9. Transcontinental Gas Pipe Line Corp., 42 FERC ¶ 61,256 at p. 61,823, *reconsideration denied*, 43 FERC ¶ 61,207 (1988).

10. *E.g.*, Natural Gas Pipeline Co., 41 FERC ¶ 61,358 at pp. 81, 972-73 (1987); Transwestern Pipeline Co., 41 FERC ¶ 61,371 at p. 62,006 (1987); Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 62,083 (1988); El Paso Natural Gas Co., 43 FERC ¶ 61,327 at p. 61,913 (1988).

11. *See* Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 61,083 (1988), and Transcontinental Gas Pipeline Corp., 46 FERC ¶ 61,364 at p. 62,135 (1989).

12. Order No. 636 at p. 30,428-29.

B. The Rationale

Cincinnati Gas attacks in part the Commission's conclusion in Order No. 636-A that 100 percent standby transportation service within firm sales entitlements is not in the public interest.[13] The Commission reached this conclusion for several reasons. First, the pipeline would still be offering a bundled sales service and therefore would be offering a service at the city gate while other gas sellers would be offering a different service because their sales would occur at or near the production area. Second, the pipeline would have a natural incentive to favor its own sales in managing the pipeline system. This would run afoul of the Commission's intent to put all sellers on an equal footing. Third, the pipeline would have to retain the gas under contract to make the bundled sales, without appropriate compensation, even though the customer would be taking the gas only or mainly at peak. Cincinnati Gas takes issue with the third rationale at least for certain pipelines, such as Columbia Gas Transmission Corporation, which has implemented a GIC that compensates it for the costs associated with maintaining its gas supply portfolio. Cincinnati Gas maintains that Columbia is thus compensated even if its customers take gas only at peak.

The Commission believes that the first two reasons are adequate to support its conclusion that 100 percent standby transportation service is not in the public interest and therefore is not a reasonable alternative to unbundling sales from transportation. Moreover, that Columbia has a GIC, and is,

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13. Under 100 percent standby service, a firm sales customer may elect to receive 100 percent of its daily contract demand volumes as firm transportation service for the shipment of gas purchased from any gas suppliers, with the pipeline obligated to stand ready to provide sales gas at call at full contract demand levels.

therefore, compensated for maintaining gas supplies, does not alter the Commission's conclusion that the transportation embedded within the bundled firm sales service is superior to firm transportation, to the disadvantage of competing sellers. Last, as stated in Order No. 636-A, "[b]ecause the Commission is determining rules of general, prospective applicability to solve 'systemic problems of the natural gas [industry],'[14] it does not need to examine the circumstances of individual pipelines."[15]

Cincinnati Gas also argues that mandating unbundling runs counter to the Commission's goal of allowing parties to rely more on private contracts.[16] It maintains that it has renegotiated its pipeline contracts since Commission Order No. 436 was implemented, and that mandating unbundling merely destroys the balance between open access and pipeline sales that it has already achieved.

The Commission sees no inconsistency between exercising its authority to find a particular type of contract (bundled sales contract) unduly discriminatory and anticompetitive, and encouraging parties to rely more on contracts in a commercial

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14. Order No. 636-A at p. 30,541, *quoting* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1166 (D.C. Cir. 1985).

15. Order No. 636-A at p. 30,541, *citing* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1165-68 and Associated Gas Distributors v. FERC, 824 F.2d 981, 1008 (D. C. Cir. 1987). Cincinnati Gas also fails to appreciate that it can contract with any gas supplier — including the pipeline — for gas that can be produced on a stand ready basis. In conjunction with the LDC's transportation entitlement, the LDC can if, it chooses replicate a standby service.

16. *Citing* Order No. 636-A at p. 30,534.

environment where no one segment of the natural gas industry has an unfair advantage over other market participants owing to its control of a monopoly service. The Commission sees no reason why Cincinnati Gas cannot continue to rely on both pipeline and non-pipeline gas merchants in the new commercial and regulatory environment created by the instant rule.

III. UNBUNDLING — PIPELINE ACCESS TO CAPACITY

In Order No. 636, the Commission concluded that pipelines must unbundle the sales and transportation components of their bundled, city-gate, sales services. In Order No. 636-A, the Commission concluded that a pipeline cannot retain or obtain capacity downstream of the point of unbundling on its system except for storage as needed for system management and balancing and no-notice transportation purposes.

Several pipelines[17] argue that this restriction on holding on-system capacity puts them at a competitive disadvantage with their competitors because the latter can effectively rebundle by holding capacity. They add that the Commission's policy may increase the level of transition costs and is not necessary to prevent the pipelines from favoring themselves in light of the Order No. 497-type safeguards of Order Nos. 636 and 636-A. Natural and Enron argue that pipelines as merchants should be able to hold capacity on their own systems. Enron, PEC Pipeline Group, and Tenneco maintain that pipelines should be able to obtain unsubscribed firm and unutilized interruptible transportation and storage capacity once sales and transportation are unbundled.

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17. Natural, Enron (Northern Natural, Transwestern, and Florida Gas), PEC Pipeline Group, and Tenneco.

Appendix D

The Commission denies rehearing and adheres to its discussion of this issue in Order No. 636-A. In brief, as stated there, the Commission believes that pipelines will be able to compete with other gas sellers for unbundled gas sales and that, "on balance any advantage on a generic basis for [pipeline] competitors [from reserving capacity for their own sales service] will be minimal and does not warrant permitting pipelines to be capacity holders and gain the opportunity to favor themselves as gas sellers in the management of pipeline transportation facilities, including storage."[18] This is especially so in the current circumstances where the pipeline must adjust from the bundled to the unbundled environment in operating the pipeline system. The Order No. 497-type safeguards imposed by Order No. 636 (standards of conduct and reporting requirements) apply only to an unbundled and not to a bundled environment. Hence, those safeguards would provide no protection against a pipeline favoring itself with its bundled sales service.

In addition, one reason for adopting the instant rule was a need to ensure equality of transportation, which the Commission continues to believe is best obtainable when the pipeline makes only unbundled sales. The pipeline differs from its competitors because of its control over a monopoly service — transportation — which its competitors must use, which gives the pipeline an inherent ability and incentive to favor its own sales service.[19] The Commission believes that it is therefore necessary to deny

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18. Order No. 636-A at p. 30,543, *citing*, Tenneco Gas v. FERC, 969 F.2d 1187 (D.C. Cir. 1992), with respect to the pipeline's "obvious incentive to favor its own marketing affiliate." (at 1202).

19. *Cf.* Tenneco Gas v. FERC, 969 F.2d 1187 (D.C. Cir. 1992), with respect to the pipeline's "obvious incentive to favor its own marketing affiliate." (at 1202).

pipelines the right to capacity on their own systems, whether retained as part of the restructuring process or obtained thereafter from unsubscribed or released capacity.[20]

The Commission notes, however, that a pipeline's merchant division can act as the gas purchaser's agent to make all arrangements necessary for transportation of the gas. However, the transportation would be accomplished through the use of the customer's transportation capacity in entitlement. In addition, a pipeline's marketing affiliate can obtain capacity on any pipeline and package sales and transportation but, in order to prevent circumvention of the unbundling requirement, the pipeline itself cannot do this.

IV. OPEN ACCESS TRANSPORTATION RULES

A. Application to Part 157 Shippers

In Order No. 636-A, the Commission determined that holders of individually certificated transportation under section 7(c) of the Natural Gas Act and Part 157 of the Commission's regulations (Part 157 shippers), *i.e.* not part 284 shippers, are not eligible to release capacity under section 284.243 since they are not governed by Part 284 or affected by the provisions of Order No. 636 that amended the Part 284 regulations.[21] For the same reason, the Commission found that Part 157 shippers would not have the same rights to flexible receipt and delivery points as Part 284 shippers.[22] The Commission stated that Part

20. For a discussion of transition costs, see *infra*.

21. Order No. 636-A at p. 30,569.

22. Order No. 636-A at p. 30,585.

157 shippers could convert to Part 284 if they wanted to release capacity or use flexible receipt and delivery points.

A number of petitioners seek rehearing of the Commission's restrictions on Part 157 shippers.[23] They contend the Commission did not adequately justify denying Part 157 shippers access to these essential services and treating them differently than other classes of firm transportation. They assert that Order No. 636 affected all industry segments, including Part 157 shippers. In particular, they cite to the requirement that Part 157 shippers must pay SFV rates and argue that they, like Part 284 shippers, need to release capacity to mitigate the effect of the change to SFV. They further contend that excluding Part 157 shippers from the capacity release mechanism and restricting their use of flexible receipt and delivery points eliminates available capacity from the secondary market and is incompatible with the Commission's goals of establishing a robust secondary market in released capacity and providing for maximum use of the pipeline system with little idle capacity.

The Commission denies the requests for rehearing. While the petitioners are correct that the rate design portion of Order No. 636 will apply to Part 157 shippers, the Commission's traditional policy is to apply the same rate design to all services. For example, the Commission applied the principles of its Rate Design Policy Statement to the design of Part 157 rates even though the Policy Statement was applicable only to Part 284

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23. AGA, Brooklyn Union, ConEd, JMC Power Projects, LILCO, Midland Cogeneration, National Fuel, New England Power, Northeast Energy, NYSE&G, Power Authority, PSE&G, SoCal Edison, Tenneco, TransCanada, Transco, UGI, Virginia Power (capacity release). JMC Power Projects, New England Power, Northeast Energy, Northern States, NYSE&G, PSE&G, Virginia Power (flexible receipt and delivery points).

transportation and the non-discriminatory access conditions of Part 284 did not apply to the Part 157 shippers.[24] Similarly, the competitive rationale for adopting SFV rate design as a means to promote the development of a national gas market[25] applies equally to Part 157 rates.

The rationale for applying SFV rate design to Part 157 rates does not justify extending the capacity release provisions, or other substantive aspects of Part 284, to Part 157 shippers. The regulations promulgated by Order No. 636 changed only the regulations under the Commission's open access transportation program implemented in Part 284 of the regulations.[26] The Commission's open access program always has been a special program with interrelated provisions designed to implement a comprehensive regulatory scheme. While Part 284 provisions may provide shippers with benefits not enjoyed by Part 157 shippers, it also imposes obligations not incurred by Part 157 shippers. Part 284 requires non-discriminatory access for all shippers, while Part 157 arrangements may include unique terms and conditions.[27] Important substantive provisions of Order No. 636 therefore do not apply to Part 157 shippers; for example, Part 157 shippers are not responsible for paying

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24. Interstate Natural Gas Pipeline Rate Design, 48 FERC ¶ 61,122, at p. 61,444 (1989) (order on rehearing).

25. Order No. 636 at pp. 30,431-35.

26. Order No. 636 applies only to pipelines operating under Part 284, except that it does not apply to intrastate pipelines and, as discussed later, section 284.242 applies to Part 157 capacity held by pipelines.

27. Penalties, for instance, must be imposed on all Part 284 shippers, but are not required to be imposed on all Part 157 shippers.

transition costs resulting from Order No. 636 and are not subject to pre-granted abandonment.[28]

Of particular relevance to the issue of capacity release, the Commission has a long standing policy of not permitting discounting under Part 157 in order to prevent undue discrimination. Selective discounting can take place only under the comprehensive regulatory scheme established in Part 284.[29] The capacity releasing mechanism established under Part 284 provided that the rates for released capacity could be discounted.[30] Indeed, the flexibility to discount rates for released capacity is an integral part of the capacity release mechanism because it promotes the Commission's goal of achieving efficient use of pipeline firm capacity throughout the year.[31] By discounting, firm shippers will be able to release capacity during the off peak season, when rates for capacity are most likely to be less than the maximum. Since the Part 284 capacity releasing mechanism is predicated on the ability to discount and Part 157 capacity cannot be discounted, Part 157 shippers cannot

28. *See* Order No. 636 at p. 30,459; section 284.221 (d).

29. *See* Consolidated Gas Transmission Corp., 36 FERC ¶ 61,723 (1986), *aff'd*, 39 FERC ¶ 61,112 (1987), *aff'd sub nom.*, Columbia Gas Transmission Corp. v. FERC, 848 F.2d 250 (D.C. Cir. 1988); Interpretation of, and Regulations Under, Section 5 of the Outer Continental Shelf Lands Act Governing Transportation of Natural Gas by Interstate Natural Gas Pipelines on or Across the Outer Continental Shelf, Order No. 509-A, 54 Fed. Reg. 8301, III FERC Stats. & Regs. Preambles ¶ 30,848, at p. 31,338 (1989).

30. Section 284.243 (e) provides that the pipeline must allocate released capacity to the person offering the highest rate (not over the maximum rate).

31. Order No. 636 at p. 30,418.

simply be included in the capacity releasing mechanism established under Part 284.

Some petitioners[32] argue that the Commission's determination that Part 157 shippers cannot release capacity under section 284.243 is inconsistent with the Commission's requirement that pipelines reassign their upstream Part 157 capacity under section 284.242.[33] The Commission finds no inconsistency between these determinations because the goals sought to be achieved by the two sections are unrelated. The capacity release mechanism was designed to enable firm shippers to reallocate unused capacity to replacement shippers wishing to obtain that capacity. On the other hand, the required assignment of upstream Part 157 capacity held by pipelines was necessary to implement the unbundling of sales and transportation service. After unbundling, firm shippers on the downstream pipeline would need upstream transportation to obtain access to supplies in the production area. Without upstream capacity, firm shippers on the downstream pipeline would have no means to transport gas from the production area to the downstream pipeline.[34] The reassignment of upstream pipeline Part 157 capacity, therefore, would have been necessary to implement unbundling fully, regardless of whether a capacity release mechanism was in place.[35]

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32. New England Power; SoCal Edison.

33. Order No. 636-A at p. 30,569.

34. Order No. 636 at p. 30,417.

35. Additionally, the reassignment of upstream pipeline capacity occurs only once and is permanent, while the capacity releasing mechanism is an on-going program.

Appendix D

Brooklyn Union contends that since no party sought rehearing of Order No. 636, which stated that Part 157 capacity could be released, the initial decision to permit such a release became final and could not be repealed without a full notice and comment rulemaking. The Commission finds this argument unpersuasive. In Order No. 636, the regulations and preamble were inconsistent on whether Part 157 shippers could release capacity, and several parties requested clarification on this point.[36] Based on such requests, the Commission can make modifications in a major rulemaking, such as this one, without embarking on a new round of notice and comment, in particular when parties have the opportunity to comment on the proposed change.[37] Brooklyn Union was given notice and the opportunity in this round of rehearing to contest the Commission's decision regarding capacity release by Part 157 shippers.

Customers on the Great Lakes system[38] contend that denying Part 157 shippers the ability to release capacity is inconsistent with Commission Order No. 368 requiring capacity release for Part 157 capacity on the Great Lakes system in order to ration capacity effectively.[39] As the Commission found in Order No. 636-A, it will not decide case-specific issues in a generic rulemaking.[40] Case-specific concerns should be

36. *See* Order No. 636-A at p. 30,565.

37. *See* Natural Resources Defense Council, Inc. v. Thomas, 838 F.2d 1224 (D.C. Cir.), *cert. denied*, 488 U.S. 888, 901 (1988); Connecticut Light & Power Co. v. Nuclear Regulatory Comm'n., 673 F.2d 525 (D.C. Cir), *cert. denied*, 459 U.S. 835 (1982).

38. Midland Cogeneration; TransCanada.

39. 57 FERC ¶ 61,141 (1991).

40. Order No. 636-A at p. 30,561.

addressed in the particular proceeding at issue or in the pipeline's individual restructuring proceeding. Rehearing of Order No. 368 in Great Lakes still is pending before the Commission.

Although the Commission is denying the requests for rehearing, the Commission reemphasizes that it finds conversions from individually certificated transportation to open access transportation to be in the public interest. The Commission anticipates that pipelines and their customers will be able to reach agreement on proposals for implementing such conversions and encourages them to do so.[41]

Several petitioners seek clarification of the mechanism by which Part 157 shippers can convert to Part 284 transportation.[42] Some contend Part 157 shippers should be given a unilateral right to convert at any time. Others argue that the pipeline must agree. Petitioners also raise questions concerning the rate implications of conversions since some Part 157 shippers now pay rates above those charged firm customers under Part 284. They request clarification whether the rates will be converted at the higher incremental level or will be rolled-in.

As a general proposition, the details of Part 157 conversions should be worked out in the restructuring proceedings so that the conversions can be coordinated with the other aspects of compliance with Order No. 636. Part 157 shippers should notify the pipeline during the restructuring of their desire to convert. The Commission will expect pipelines to implement such

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41. *See* Transcontinental Gas Pipe Line Corp., 60 FERC ¶ 61,388 (1992).

42. PSE&G; National Fuel; Transco; LILCO; New England Power; Midland Cogeneration.

conversions to the maximum extent feasible. However, since rate and other implications of Part 157 conversions are specific to individual pipelines, the Commission cannot specify a universal mechanism for handling these concerns; these issues are more appropriately addressed in individual cases.

B. Capacity Release

In Order No. 636, the Commission added section 284.243 requiring open access pipelines to establish a mechanism that permits firm transportation customers under Part 284 to release all or part of their capacity to a replacement shipper. In Order No. 636-A, the Commission added section 284.243(h) providing an exception from the bidding requirements of section 284.243 for short-term capacity releases, modified section 284.243(d) to require pipelines to post offers to purchase capacity, and addressed numerous requests for rehearing and clarification. Except when necessary to respond to petitioners' arguments on rehearing and clarification of Order No. 636-A, the Commission will not repeat here the discussion of the capacity release mechanism in Order Nos. 636 and 636-A.

1. Maximum Rate Bids

CNG requests clarification that if a designated replacement shipper under a prearranged deal bids the maximum rate, the pipeline need not post the transaction on the EBB or, in the alternative, could post the transaction within 48 hours of the completed transaction. The Commission will clarify the appropriate handling of prearranged deals at the maximum rate (meeting all terms and conditions of the release). One of the primary goals of the capacity release provisions was to provide timely notice of all capacity reallocations and CNG has provided

no basis for concluding that such posting would be any more burdensome than posting other listings of capacity available for release. Thus, CNG's request for an exception from the posting requirements for capacity released at the maximum rate is denied; under section 284.243(d), pipelines must post immediately all capacity available for release, including those involving designated replacement shippers paying the maximum rate.[43]

However, when a prearranged deal is at the maximum rate, and meets all other terms and conditions of the release, no other shipper can make a better bid for that capacity, and, therefore, subjecting such a release to the bidding periods in the pipeline's tariff could unnecessarily delay implementation of the release. Accordingly, the Commission expects pipelines to adopt procedures to provide for prompt implementation of prearranged deals at the maximum rate.

2. Exception for Short-Term Releases

In Order No. 636-A, the Commission promulgated new section 284.243(h) providing that parties could arrange for releases of capacity of less than one calendar month without compliance with the bidding requirements of section 284.243. Notice of the release would have to made as soon as possible, but no later than 48 hours after the release transaction begins. While petitioners generally were supportive of the short-term exception, they have requested rehearing on two aspects of the provision.

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43. Releases falling under the short-term exception in section 284.243(h) must be posted as soon as possible, but not later than 48 hours after the transaction commences.

Appendix D

a. Length of release

Several petitioners request that the exception be extended to one full month so that it will conform better to the industry's current practice in which contracts for spot market gas cover a full month.[44] The Commission denies the request for rehearing on this point. The short-term exception was designed to ensure that firm shippers have the ability to release capacity in unforseen situations when they cannot anticipate having capacity available. It was not designed as a substitute for the section 284.243 bidding procedures for normal industry transactions. The Commission remains convinced that pipelines can design capacity release mechanisms to accommodate the industry's standard monthly contracting process. Indeed, in most cases, the Commission expects that pipelines can implement capacity releases mechanisms under the regulations that will accommodate releases for one day or less anytime during a month and provide for consummation of such transactions within twenty-four hours of posting.[45]

b. Prohibition on roll-overs

In section 284.243(h)(2), the Commission prohibited roll-overs or extensions under the exception as well as re-releases of capacity to the same replacement shipper within 30 days of the first release. Parties wishing to extend such releases would have to comply with the posting and bidding requirements of the rule. The Commission included these prohibitions on roll-overs to protect the integrity and allocative efficiency of the capacity

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44. AGA; Natural; NYSE&G; Peoples Gas.

45. *See* Order No. 636-A at p. 30,554.

release mechanism by preventing parties from avoiding the bidding requirement by extending short-term releases.[46]

Several petitioners request the Commission to remove these prohibitions on roll-overs.[47] They contend that an exigency may reoccur within a month, requiring a re-release of capacity to the same replacement shipper. AGD gives, as an example, a power outage resulting in excess capacity to an LDC which could recur later in the month.

The Commission denies the requests for rehearing. In the Commission's judgment, the need to prevent circumvention of the bidding process should not be sacrificed to accommodate the remote possibility that an unforseen situation will reoccur more than once a month. Moreover, the Commission has provided flexibility to accommodate even such remote exigencies. The releasing shipper could release capacity to another replacement shipper under the short-term exception. As discussed previously, the releasing shipper also could enter into a pre-arranged deal with the same replacement shipper at the maximum rate. Such a deal would not be subject to any bidding periods and the Commission expects that pipelines will be able to provide for prompt implementation of such deals.

Petitioners also contend that some replacement shippers require quick access to short-term capacity on a recurring basis

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46. The Commission found that prearranged deals ordinarily must be subject to the bidding requirements of section 284.243 to preserve allocative efficiency by ensuring that capacity is allocated to the shipper placing the highest value on that capacity. Order No. 636-A at pp. 30,554-55.

47. AGA, AGD, CNG, Northern States; PSE&G; UGI; UDC; Washington Gas.

and that the prohibition on roll-overs would preclude such transactions from taking place. As noted above, the short-term exception was not intended to permit parties to structure on-going transactions involving recurring access to capacity over short periods. Such ongoing, recurring transactions must be subject to bidding (unless at the maximum rate) and the other non-discriminatory requirements of the capacity releasing mechanism to ensure that capacity is allocated to the replacement shipper placing the highest value on the capacity.

Consolidated Minerals, on the other hand, contends that the Commission's prohibition on roll-overs is not strong enough to prevent circumvention of the non-discriminatory bidding requirements of the capacity release mechanism. It requests stronger provisions, such as volumetric limitations or further limits on the frequency with which parties can use this process. The Commission will not impose volumetric limits or further restrictions to prevent roll-overs, because such restrictions would place burdens on short-term releases that do not appear necessary to prevent circumvention of the bidding process.

3. Requests for Additional Exceptions

In Order No. 636-A, the Commission rejected requests for exceptions from its rule that a replacement shipper under a prearranged deal has priority to released capacity so long as the prearranged replacement shipper meets the maximum price bid.[48] American Natural Gas and Consolidated Minerals reiterate the request for alternative priority mechanisms, arguing, in particular, that providing prearranged deals with priority to released capacity on capacity constrained pipelines will result in an unfair allocation of capacity.

48. Order No. 636-A at pp. 30,554-56.

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The Commission reaffirms its position in Order Nos. 636 and 636-A and will not provide for alternative priority provisions on capacity constrained pipelines. Such an exception could involve numerous pipelines or portions of pipelines and would defeat the efficiency goals of the capacity release mechanism. As stated in Order No. 636-A, prearranged deals promote efficiency by providing firm shippers with the incentive to market actively their unneeded firm capacity rather than simply posting it on the bulletin board. However, the Commission sought to preserve the allocative efficiency of the process by requiring that prearranged deals be subject to the bidding requirements of section 284.243 so that the available capacity is allocated to its highest valued use.[49]

Washington Gas suggests that, in Order No. 636-A, the Commission limited the use of prearranged deals to agreements between LDCs and end-users and suggests that this limitation fails to recognize that LDCs may need to enter into pooling or exchange arrangements among themselves to provide peaking service or emergency replacement of supplies in the event of a force majeure outage.[50] It further requests that the Commission permit LDCs to enter into such exchange or pooling arrangements without EBB posting.

Washington Gas is not correct that prearranged deals are limited to arrangements between LDCs and end-users; the section cited by Washington Gas merely referred to deals between LDCs

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49. In Order No. 636-A, the Commission denied a similar request for according shippers on a pipeline's firm queue with priority access to released capacity. Order No. 636-A at p. 30,555.

50. Washington Gas cites the discussion in Order No. 636-A at p. 30,555.

and end-users as an example of one type of prearranged deal. LDCs can enter into prearranged deals with other LDCs or any other potential shippers. However, Washington Gas has not demonstrated that so-called pooling and exchange arrangements, or similar arrangements, are so different from other prearranged deals that they warrant an exception from the posting requirements. All prearranged deals for release of capacity must either fall within the short-term exception in section 284.243(h) or comply with the posting and bidding requirements of section 284.243.

4. Terms and Conditions

Order No. 636 provided that releasing shippers could establish terms and conditions specific to their releases, such as the right to recall the use of capacity under certain conditions, for instance, if the temperature dropped below a specified degree.[51] In Order No. 636-A, the Commission clarified a number of issues relating to terms and conditions. The Commission stated that releasing shippers could include reasonable and non-discriminatory terms and conditions and could include provisions for determining the highest valued or best bid. The Commission required that all such terms and conditions must be posted on the pipeline's EBB, be objectively stated, be applicable to all potential bidders, and relate solely to the details of acquiring capacity on interstate pipelines.[52] With respect to the determination of best bids, the Commission also required the pipelines to include in their tariffs an objective and non-discriminatory economic standard for determining best bids. Releasing shippers could avail themselves of this standard, but were not required to do so.

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51. Order No. 636 at p. 30,418.

52. Order No. 636-A at p. 30,557.

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CIG contends the Commission erred in permitting the releasing shipper to establish terms and conditions for determining best bids and should, instead, require the pipelines and their customers to craft a generic set of evaluation criteria for determining best bids. It asserts that allowing the releasing shipper to dictate bid evaluation criteria will burden the administration of the capacity release program and could lead to discriminatory conduct, for example, if releasing shippers favor their own end-users.

The Producer Associations argue that the capacity release mechanism should protect small shippers and contend that bid evaluation should be done solely on the basis of price without consideration of the volumes bid by any shipper. Under its proposal, a shipper bidding a high price for a small volume would receive that capacity even though another shipper bid a somewhat lower price for the entire package.

The Commission denies the requests for rehearing. In Order No. 636-A, the Commission recognized that a variety of releasing conditions might exist and that one methodology for evaluating bids might not apply equally to all releases.[53] In balancing the need to permit releasing shippers to develop terms and conditions that would maximize the efficiency of their capacity releases against the need to prevent discrimination, the Commission concluded that it would not prohibit releasing shippers from developing objective, non-discriminatory terms and conditions to determine the best bid.[54] The Commission,

53. Order No. 636-A at p. 30,556. For example, the Commission recognized that in some circumstances, releasing shippers may be releasing capacity on both downstream and upstream pipelines. Order No. 636-A at p. 30,558 n.144.

54. The pipeline's tariff standard for evaluating bids would apply when the releasing shipper did not specify its own standard.

however, specifically provided that such terms and conditions could not favor one set of buyers or grant price preferences or credits to certain buyers. The Commission believes such regulations are sufficient to prevent undue discrimination. Applying objectively stated criteria also should pose little administrative difficulty. Because releasing situations are so varied, the Commission will not circumscribe the options of the parties by proscribing particular evaluation methodologies, such as those suggested by the Producer Associations.

Other petitioners raise additional issues with respect to terms and conditions. UGI and UDC reiterate the argument advanced on rehearing of Order No. 636 that releasing shippers should be allowed to establish bid evaluation criteria that reflect all factors affecting the releasing shipper; UGI contends, for example, that LDCs should be able to establish criteria to permit them to recover the cost of their own facilities that would become effectively stranded if an off-system replacement shipper acquired the LDC's pipeline capacity. PG&E contends that parties should be able to agree on prearranged deals involving terms and conditions that are not posted as conditions of the capacity release. ANR requests guidance on issues relating to recall rights, such as who will be responsible for invoking recall rights and whether the pipeline will be insulated from liability associated with proper recalls. It requests clarification that pipelines are free to devise tariff provisions to determine liability for imbalances associated with recalls.

The Commission denies these requests. The Commission continues to hold the same position it stated in Order No. 636-A. All terms and conditions for releases, including those providing for recalls, must be posted on the EBB, must be objectively stated, must apply only to release of pipeline capacity,

must not prefer any shipper, such as an end-user, over other shippers, and cannot take into account the use of an LDC's own facilities. As the Commission pointed out in Order No. 636-A, an LDC can negotiate a prearranged deal with an end-user and the end-user will receive the capacity as long as it matches the best offer.[55] Issues of defining rights and responsibilities relating to recalls should be considered in the restructuring proceedings and included in the tariff provisions in the pipelines' compliance filings.

5. Volumetric Bids

Western Resources and the Producer Associations request reconsideration of a statement in Order No. 636-A which they interpret as forbidding a releasing shipper from accepting bids for released capacity on a one-part volumetric basis. In Order No. 636-A, the Commission addressed a request to establish the maximum rate for released capacity as equal to the maximum rate for interruptible transportation. In response, the Commission stated that the maximum rate for released capacity normally would be the maximum firm rate since the releasing shipper is releasing firm capacity and the replacement shipper is paying a monthly reservation charge.[56] The Commission, however, was addressing the maximum rate issue only with respect to this common releasing scenario. As a general policy, the Commission seeks to promote competition between pipeline capacity and released capacity. To facilitate such competition, the Commission will not foreclose released capacity from being bid on a volumetric basis. The Commission will clarify that parties to the restructuring proceedings can propose mechanisms that

55. Order No. 636-A at p. 30,555.

56. Order No. 636-A at p. 30,560.

would permit shippers to release capacity on a volumetric basis if they choose to do so.

6. Use of Released Capacity for Backhauls

WGM requests clarification that a releasing shipper can release capacity it currently uses as a forward haul for use as a backhaul, if such use is operationally feasible. WGM contends that a backhaul resulting in a change in the flow direction should be permitted if such a change is operationally feasible or if the shipper is willing to pay the cost of making it feasible.

In Order Nos. 636 and 636-A, the Commission established the general principle that firm shippers should be able to make full use of their pipeline capacity through release transactions. The Commission used as an example a releasing shipper with capacity between the Gulf of Mexico and New York releasing capacity from the Gulf to Atlanta; this transaction would then free up an equal amount of capacity from Atlanta to New York which the shipper could release or use itself.[57] The releasing shipper could release its capacity in this manner even though the total amount of gas delivered from the two transactions could exceed its total reservation quantity from the Gulf to New York. This principle should be applied to capacity release arrangements between releasing and replacement shippers that involve backhauls or exchanges. The Commission, however, cannot make a generic determination on WGM's questions with respect to physical changes in flow direction, since operational questions must be determined on the basis of the characteristics of each pipeline.

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57. Order No. 636-A at p. 30,559 n.151.

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7. Credits Exceeding Reservation Fee

Section 284.243(f) provides that releasing shippers receive the full proceeds from any release. In Order No. 636-A, the Commission denied requests for modifying this principle as applied to shippers paying discounted rates.[58] Three petitioners seek rehearing of the Commission's determination that shippers holding discounted contracts should receive the full proceeds from a release, making essentially the same arguments addressed in Order No. 636-A.[59] They contend that the pipeline entered into discounted contracts based on specific circumstances in order to retain firm transportation that was in danger of being lost, the pipeline will be harmed if these customers could release their capacity to other shippers, and the holders of discounted contracts would enjoy an advantage over shippers paying maximum rates.

For the reasons stated in Order No. 636-A, the Commission again denies the requests for rehearing. Holders of discounted capacity have no competitive advantage in the release market over shippers paying maximum rates, since all firm shippers will be releasing capacity under the same conditions.[60] Further, as the Commission pointed out, pipelines are no worse off if holders of discounted contracts can release capacity; the pipeline still receives the same total reservation charges and revenue as it did prior to the release.

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58. Order No. 636-A at pp. 30,561-62.

59. Arkla; CIG; Enron.

60. Replacement shippers will be able to bid for all available capacity up to the same maximum rate and therefore will have no incentive to favor a release from a shipper holding discounted capacity over a release from a customer paying the maximum rate.

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8. Capacity Releasing by Small Customers Paying a One-Part Rate

In Order No. 636-A, the Commission clarified that pipelines offering a small customer sales or firm transportation service at an imputed load factor rate must continue to offer firm and no-notice transportation on the same basis.[61] Several petitioners request rehearing or clarification, contending that the small customers electing service under a one-part volumetric rate should be prohibited from releasing capacity under the capacity release mechanism of section 284.243.[62] They contend that permitting such releases would provide these customers with a double benefit or would provide them with competitive advantages in the releasing market. If the Commission permits small customers to release capacity, the Northern Distributor Group contends that the release should be at a rate equal to the pipeline's two-part rate, while Southern argues that the small customers should be required to pre-pay their one-part rate prior to releasing. Prior Energy, on the other hand, argues that small customers should be able to release capacity and requests clarification of the maximum rate for such releases.

Because small customers paying a one-part volumetric rate are not paying a reservation charge to reserve the capacity, the Commission clarifies that they cannot release that capacity under the capacity release mechanism.[63] However, small customers

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61. Order No. 636-A at p. 30,600.

62. Atlanta Gas; Northern Distributor Group; Southern.

63. The capacity release mechanism was designed so that payments from a replacement shipper will be credited to a releasing shipper's reservation charge. *See* section 284.243(f).

paying a two-part rate including a reservation fee will be permitted to release that capacity. The parties in the restructuring proceedings should work out details relating to releases of capacity under small customer two-part rate schedules, including the development of procedures to enable customers served under a one-part rate schedule to convert to a two-part rate schedule if they choose to convert in order to release capacity.

9. Responsibility for Penalties

Section 284.243(f) provides that, unless the pipeline agrees otherwise, a releasing shipper remains liable under its contract with the pipeline. In Order No. 636-A, the Commission clarified that if a replacement shipper defaults, the releasing shipper is responsible to the pipeline for the continued payment of reservation charges, but not for penalties or other charges incurred by the replacement shipper as a result of its own conduct.[64] Arkla requests clarification that releasing shippers still will be ultimately liable for monthly surcharges, such as GSR charges, and other charges not the result of the replacement shipper's conduct. CNG requests clarification that the Commission was not predetermining the issue of a releasing shipper's liability and that a releasing shipper can be held liable for penalties if it is partly responsible for the conduct.

In Order No. 636-A, the Commission set out the general parameters for determining whether releasing shippers should be liable for penalties and other charges in the event of defaults by the replacement shippers. As a general matter, releasing shippers are ultimately responsible for items included in reservation charges (amounts for which they would be responsible if no release took place), but are not responsible for

64. Order No. 636-A at p. 30,565.

assessments included in the usage charge or penalties caused by the conduct of replacement shippers. For example, releasing shippers ultimately would be responsible for payment of a full reservation fee and any GSR demand surcharge applicable to that fee. The parties in the restructuring proceedings should craft appropriate tariff language along those lines.

10. Contractual Privity

UGI and UDC repeat the request, denied in Order No. 636-A, that the Commission establish contractual privity between releasing and replacement shippers. UDC suggests that releasing shippers be able to include, as a term and condition of release, an indemnification agreement between the releasing and replacement shipper. As determined in Order No. 636-A, the Commission will not compel pipelines to require contractual privity between releasing and replacement shippers, since privity and subrogation are matters of state law and should be governed by that law and the contracts of the releasing shipper and the pipeline.[65] Releasing shippers can include any non-discriminatory term and condition in their offers to release and therefore could include the requirement for replacement shippers to enter into an indemnification agreement, but the interpretation of any such agreement would be a matter for state law.

11. Releasing Shipper's Liability

Barclays and Mojave request clarification that the capacity releasing mechanism will not impair the ability of pipelines to

65. "[P]robably there are few doctrines better established than that a surety who pays the debt of another is entitled to all the rights of the person he paid to enforce his right to be reimbursed." Pearlman v. Reliance Insurance Co., 371 U.S. 132, 136-37 (1962).

recover their full cost-of-service. Barclays seeks assurance that a project financed pipeline will be protected from a shortfall in price and in contract duration when capacity is reassigned. Mojave seeks clarification that it will be able to tailor its capacity release program to deal with case specific issues stemming from the rate design and contracts on its system so as to ensure its ability to recover its cost-of-service.

As discussed in Order No. 636-A, the capacity release mechanism promulgated in section 284.243 does not change the relationship between the firm capacity holder (releasing shipper) and the pipeline and therefore will not result in any diminution of revenue received by the pipeline. Section 284.243(f) provides that the contract of the releasing shipper and the pipeline still remains in full force and effect.[66] As the Commission explained in Order No. 636-A, the releasing shipper is therefore ultimately responsible for paying the pipeline the full amount of its reservation fee.[67] The Commission will consider Mojave's or any other case specific concerns in the restructuring proceedings for each pipeline.

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66. Similarly, the Commission clarified in Order No. 636-A that for capacity reallocations on project financed pipelines under sections 284.14(e) and 284.242, an assignor of capacity must serve as a guarantor of payments under the existing contract unless creditor approval of the assignment is obtained, where necessary, and the project financed pipeline agrees to release the assignor from liability. Order No. 636-A at p. 30,674.

67. Order No. 636-A at p. 30,560. The pipeline will bill the replacement shipper for the amount it bid for the reservation fee (to be credited to the releasing shipper) and for the applicable usage fee. For accounting purposes, the pipeline bill to the releasing shipper should reflect a simultaneous credit to the releasing shipper for the reservation fee billed the replacement shipper. If the replacement shipper defaults, the pipeline will bill the releasing shipper for the unpaid amount on the next bill.

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12. Interruptible Rate Design

In Order No. 636-A, the Commission addressed issues regarding the development of a rate design for interruptible transportation after the implementation of a capacity release mechanism.[68] The Commission traditionally has required that a pipeline recover a certain amount of fixed costs (its revenue responsibility) from interruptible transportation based on a projected level of interruptible throughput. On rehearing of Order No. 636, several parties were concerned about the difficulty in accurately projecting interruptible throughput and revenue responsibility when the pipelines and their customers have had no experience with the effect of capacity releasing on the throughput levels for interruptible transportation. The release of firm capacity also may affect the rates charged for interruptible transportation since the competition from released capacity might require the pipelines to offer greater discounts for interruptible transportation than they had in the past.[69]

In Order No. 636-A, the Commission found that promoting competition between released and interruptible transportation was an important policy objective. The Commission recognized that competition between released firm and interruptible transportation, together with the potential use of seasonal contract demands, could affect the level of interruptible transportation and provided that the throughput mix between

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68. Order No. 636-A at pp. 30,562-63.

69. For example, if the projected revenue responsibility for interruptible transportation were higher than actual experience, the pipeline might not recover the fixed costs assigned to interruptible transportation. On the other hand, if the projection were too low, the pipeline could recover much more than the costs allocated to the interruptible service.

interruptible and firm transportation should be considered in the restructuring proceedings.[70] In handling this issue, the Commission stated that the parties to the restructuring proceedings could consider a variety of approaches, such as agreeing on an appropriate level of throughput for interruptible transportation or some type of revenue crediting mechanism. Although not mandating the adoption of any technique, the Commission provided an outline of a potential revenue crediting approach under which the pipeline would allocate no costs or revenue responsibility to interruptible service, but would credit firm shippers with interruptible revenue generated. The firm shippers would receive the credit because under this allocation of costs, the firm rate would recover all the fixed costs of the pipeline.

Several petitioners contend that the Commission erred in even suggesting that a revenue crediting mechanism might be appropriate for dealing with the difficulty of projecting interruptible revenues.[71] They contend that revenue crediting is inconsistent with section 284.7(d)(2) of the Commission's regulations, which provides that rates must be designed to recover costs on the basis of projected units of service. They assert that revenue crediting conflicts with the purpose of this section, because it provides the pipeline with no incentive to provide the service. LILCO argues that interruptible transportation should be subject to the same posting and bidding requirements as released capacity to ensure that neither interruptible nor released capacity will have an inherent advantage over the other service. Although not entirely clear from its comments, LILCO appears to propose that pipelines be obligated to sell interruptible

70. Order No. 636-A at p. 30,563.

71. Arcadian; ConEd; Industrial Groups.

service to the highest bidder, rather than being able to selectively discount.

The petitioners requesting rehearing have not been aggrieved by the suggestion that the Commission would consider a revenue crediting approach proposed in a specific restructuring proceeding. In implementing its regulations, the Commission will not adopt rigid rate-making methodologies that fail to reflect the reality of the market or the intent of its regulations. When the Commission permitted discounting of interruptible transportation, it had to adopt rate-making methodologies for projecting revenue responsibility that would not penalize the pipeline for discounting interruptible service.[72] The Commission suggested a similar revenue crediting mechanism as a means of dealing with the difficulty of estimating discounting.[73] The Commission will not foreclose the parties in the restructuring proceedings from considering revenue crediting or other approaches, such as LILCO's proposal for bidding on interruptible transportation, as methods for dealing with the uncertainties resulting from the implementation of a capacity releasing mechanism.[74] If the Commission adopts a revenue crediting or other approach in a pipeline's compliance filing, it will reevaluate any such mechanism in the pipeline's next rate case after the parties have experience with capacity releasing.

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72. *See* Associated Gas Distributors v. FERC, 824 F.2d 981, 1012 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

73. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, at pp. 62,056-57 & n. 49 (1989).

74. In response to LILCO's request that interruptible capacity be subject to the same posting requirements as released capacity, the Commission notes that section 284.9(b)(3)&(4) already requires pipelines to post information about interruptible service on an EBB.

Questar requests clarification that under a potential revenue crediting approach the pipeline would not have to credit firm shippers for the portion of interruptible revenue reflecting its variable costs (usage charge). The Commission will clarify that the revenue credit should apply only to the extent that revenues from interruptible transportation recover costs allocated to firm transportation. Pipelines would be able to retain the usage component of the interruptible rate so long as the usage charge is calculated on the basis of total throughput.

13. Administrative Issues Involving Capacity Release

a. Electronic bulletin board

In Order No. 636, the Commission required that pipelines conduct their capacity release programs through electronic bulletin boards (EBBs). In Order No. 636-A, the Commission directed the pipelines to provide for interactive EBBs in their compliance filings or to provide a reasonable explanation of their inability to do so.[75] The Commission further encouraged the industry to develop uniform standards and conventions for EBBs and committed to establish a technical conference to determine the industry's progress in developing interactive, user-friendly EBBs and uniform EBB standards.

Williston and ANR request clarification of the requirements needed to make EBBs interactive, since they claim capacity release is not simply a transaction between the releasing and replacement shipper, but requires some pipeline involvement. ANR suggests that, in certain situations, transactions could be consummated on the EBB without any, or with limited, pipeline intervention.

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75. Order No. 636-A at p. 30,549-50.

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The Commission did not seek to define the precise parameters of an interactive EBB, believing that the industry, through the restructuring proceedings, is in the best position to reach such determinations. As a general matter, the Commission expects pipelines to provide EBBs that will permit posting of capacity available for release and bids for that capacity directly on the EBB, and electronic confirmation of the completed transaction on the EBB. The Commission envisions that, in the near future, all pipelines should be able to provide for entire transactions to take place using EBBs, including, for example, electronic contractual consummation of completed transactions.

UGI and the Industrial Groups argue that EBBs are the key to capacity reassignment and that the Commission must take action to ensure that EBBs on different pipelines are coordinated. They urge the Commission to defer mandatory bidding through EBBs until a coherent national or regional EBB policy is established. UGI reasserts its position that facilities and personnel running the EBB should be separate from those used for managing interruptible transportation to ensure that the pipelines do not abuse the EBB process for competitive purposes.

The Commission will not defer the requirement for conducting capacity release transactions through an EBB. The capacity release mechanism is an integral part of the restructuring required by Order No. 636 and therefore must be implemented at the same time as the other requirements of Order No. 636 to ensure that the parties have a mechanism for reallocating capacity.[76] While the Commission believes that EBB technology

76. As discussed in Order No. 636-A, the Commission will not permit reallocations of capacity to take place without compliance with the posting

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and coordination may improve over time, it is convinced that the pipelines currently have the ability to develop effective EBBs and capacity release mechanisms. The Commission also believes that the industry, not the Commission, is in the best position to develop the specific technical standards for EBBs and for coordination among EBBs. The Commission considers its most effective role as facilitating the process of improving EBBs by bringing those with the technical expertise together in a technical conference.

The Commission adheres to its determination in Order No. 636-A that separation of EBB personnel is not necessary to prevent the pipelines from giving undue preference to their own interruptible transportation. As discussed in Order No. 636-A, the Commission has taken a number of steps which it believes are all that is currently needed to address this issue.[77]

b. Implementation of releases

ANR and CIG request clarification that pipelines can adopt procedures for capacity release that provide sufficient advance notice to accommodate the pipelines' contract administration process. The Commission is not sure whether these requests apply to releases under the short-term exception or under the general bidding requirements of the capacity release mechanism.

With respect to the short-term exception under section

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and bidding requirements of section 284.243 to ensure that capacity reallocations can be effectively monitored for possible undue discrimination. Order No. 636-A at pp. 30,552-53.

77. Order No. 636-A at pp. 30,563-64.

284.243(h), the Commission adopted this exception specifically to avoid any impediments to short-term releases of capacity and therefore the pipelines should not adopt any procedures that would interfere with the execution of releases under the short-term exception. With respect to releases under the general provisions of section 284.243, the Commission reiterates its position in Order No. 636-A that, in most instances, pipelines should be able to provide procedures to accommodate short-term releases on the EBB so that release transactions can take place for one day or less any time during the month and that such transactions can be finalized within 24 hours.[78] Pipelines must justify any provisions that do not meet this standard. In Order No. 636-A, the Commission suggested that the parties to the restructuring proceedings consider pre-qualification for creditworthiness as a means to expedite releases,[79] and they similarly should consider appropriate mechanisms for dealing with contract execution and other issues so as to ensure a viable capacity release mechanism.

c. Administrative fee

In Order No. 636-A, the Commission provided that pipelines could not recover the costs of operating their capacity release programs through a separately stated administrative fee, but instead should include the fixed costs of their programs in their rates. The pipelines, however, could charge a fee for using the EBB that reflected the variable costs of such use.[80] In addition, the Commission required that pipelines must permit

78. Order No. 636-A at p. 30,554.

79. Order No. 636-A at p. 30,558.

80. Order No. 636-A at p. 30,564.

posting on the EBB of offers to purchase capacity and stated that the shipper posting such offer would have to pay any posting fee required.[81]

CIG and Tenneco request rehearing, contending that the Commission should permit a separately stated administrative fee for using the EBB that covers fixed and variable costs so that only shippers making use of the EBB would pay the costs of providing the service. ANR and CNG request clarification that the separately stated usage fee reflecting variable costs would be charged to the users of the EBB, not through commodity rates. CNG also requests clarification that the Commission's reference to a posting fee for offers to purchase capacity refers to the separately-stated usage fee for use of the EBB.

The Commission required the pipelines to recover the fixed costs for operating the capacity release program through their rates to ensure that the market for released firm capacity was not unduly burdened by high rates for using the EBB and thereby placed at a disadvantage to interruptible capacity. The Commission continues to find this rationale persuasive and therefore denies CIG's and Tenneco's requests for rehearing. The Commission reiterates that the pipelines may charge a separately stated usage fee, reflecting only the variable costs of usage, charged to those using the EBB.[82] The Commission clarifies that shippers posting offers to purchase capacity can be charged only the same usage fee assessed other users of the EBB.

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81. Order No. 636-A at p. 30,565.

82. Pipelines need to demonstrate that the costs included in the EBB usage charge reflect only the variable costs of customers' use of the EBB.

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14. Retention of Capacity Brokering

In Order Nos. 636 and 636-A, the Commission concluded that, with the adoption of a capacity release mechanism, it should not approve new individually authorized capacity brokering and other capacity assignment certificates. In addition, in a separate order issued April 8, 1992, the Commission amended the terms and conditions of existing capacity brokering and other assignment programs to conform to the capacity reallocation mechanisms adopted in Order No. 636.[83]

The AGA argues that the Commission should allow the parties to the restructuring proceedings to develop workable alternatives to capacity releasing under the rule and not ban programs similar to capacity brokering. The AGA concludes that "where state commissions are actually regulating, or seek to regulate, capacity brokering, it would be beneficial to allow capacity brokering programs to develop under state purview."[84]

For the reasons given in Order Nos. 636 and 636-A and in the *Algonquin Gas Transmission Co.* orders of May 8 and August 3, 1992,[85] the Commission denies AGA's request for rehearing. In brief, the Commission believes that exclusive federal regulation of interstate capacity assignment programs is necessary to establish a uniform capacity reallocation program, which the Commission can monitor to ensure that the secondary transportation capacity market operates without discrimination.

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83. Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992), *reh'g denied*, 60 FERC ¶ 61,113 (1992).

84. Petition at 4.

85. 59 FERC ¶ 61,032 and 60 FERC ¶ 61,113 (1992).

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15. Buy/Sell Arrangements

The Commission concluded in *El Paso Natural Gas Co.* that it has jurisdiction over buy/sell arrangements where, for example, an LDC purchases gas in the production area from an end user or merchant designated by an end user, ships the gas on its (the LDC's) own capacity, and sells the gas to the end user at the retail delivery point.[86] In Order Nos. 636 and 636-A, the Commission concluded that as of the effective date of a pipeline's compliance with Order No. 636, no new buy/sell arrangement can be consummated and all allocations of capacity must be done under the capacity releasing mechanism.

PSE&G asks the Commission whether the Commission's ban applies only to LDCs or also applies to marketers and producers. The Commission concludes that the prospective ban on buy/sell arrangements applies to all holders of capacity on an interstate pipeline for the reasons set forth in *El Paso*, *supra*. The Commission sees no difference between LDCs and other capacity holders with respect to the Commission's determination "that to permit the coincidence of buy/sell transactions with capacity reallocation under the mechanism established in Order No. 636 would interfere with our objectives in creating a nationally uniform [capacity release] program."[87]

16. Jurisdiction Over Municipalities

In Order No. 636-A, the Commission concluded that while

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86. 59 FERC ¶ 61,031 (1992), *order denying reh'g and clarifying prior order*, 60 FERC ¶ 61,117 (1992), *appeal docketed*, Windward Energy & Marketing Co. v. FERC, No. 92-1361 (D.C. Cir. Aug. 13, 1992).

87. 60 FERC ¶ 61,117 at p. 61,384.

municipalities are beyond the jurisdiction of the Commission, they may release capacity on a pipeline only by complying with the procedures pertinent to the pipeline's releasing mechanism because the conditions of the program pertain to the mechanics of the release by and through the pipeline.

The APGA and Citizens Gas seek rehearing of the Commission's conclusion that municipalities must comply with the requirements of a pipeline's capacity release program. They argue that the Commission has exceeded its authority under the NGA because a municipality is not a natural gas company as defined in NGA section 2. They add that the Commission has expressly held in two orders with respect to capacity brokering that municipalities are not subject to the Commission's NGA jurisdiction.[88] They maintain that the difference between capacity brokering and releasing — that is, that under the former assignments may be effected directly while under the latter may only be effected through the pipeline — does not modify the NGA's exemption for municipalities. The APGA maintains that municipalities may release capacity without restriction on the contractual price negotiated or the choice of buyer. Citizens Gas contends that municipalities may not be subjected to Commission action that would restrict substantially their ability to release, including by implication buy-sell agreements.

The Commission denies rehearing. While the Commission has no NGA jurisdiction over municipalities as gas sellers or transporters, the Commission has exclusive preemptive jurisdiction over access to interstate pipeline capacity.[89] The

88. Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 (1990), Texas Gas Transmission Corp., 55 FERC ¶ 61,208 (1991).

89. See the discussion in El Paso Natural Gas Co., 60 FERC ¶ 61,117 at p. 61,384 (1992).

Commission's authority over transportation by a pipeline under the NGA includes the eligibility criteria for becoming a shipper.[90] The Commission sees this as no different from its authority to determine terms and conditions of service, which the APGA concedes municipalities should abide by.[91] Whether the shipper is a natural gas company is irrelevant to the Commission's plenary authority over access to interstate pipeline capacity under the NGA.

The cases cited by petitioners are not on point. It is true that they hold that municipalities need not be certificated in a capacity assignment program and that they need not comply with conditions imposed upon program participants as transporters. However, as the Commission concluded in Order No. 636-A, those cases are not controlling when the Commission has exercised its authority to require that releases be effected by and through the pipeline. In that event, the capacity releasing mechanism in its entirety must be complied with just as a municipality must comply with any other pipeline term or condition of service. To allow municipalities to freelance their releasing would not be in harmony with the Commission's goals of a uniform capacity reallocation program to eliminate discrimination in the assignment of pipeline capacity. Of course, the municipalities are not covered by the Commission's grant of a limited jurisdiction certificate in section 284.243(g) of the Commission's regulations.

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90. *Cf.* Mississippi River Transmission Corp. v. FERC, 969 F.2d 1215, 1217 (D.C. Cir. 1992) (The Commission's authority over the transportation of gas in connection with an unregulated direct sale "is beyond dispute.")

91. *Cf.* FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972) (The Commission has authority over curtailment programs under its jurisdiction over transportation).

Finally, to grant APGA's request would create a regulatory gap that would frustrate the non-discrimination feature of Order No. 636. Most municipalties are self-regulated (*i.e.*, not subject to state commission authority). To grant APGA's request would, therefore, create a class of shipper controlling access to interstate capacity without either federal or state commission review. This regulatory gap would give municipalities a competitive and otherwise non-market advantage over all other shippers. Simply put the fundamental premise of capacity releasing — to ensure non-discriminatory access to the secondary transportation market — would be undermined. Allowing such a regulatory gap to exist in regulatory access to the interstate market is not in the public interest.

C. Upstream Capacity Assignment

In Order No. 636, the Commission adopted new section 284.242 of its regulations, which provides that open-access pipelines must allow firm transportation customers of downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines. The main issues raised are whether bundled sales customers should have a priority in acquiring upstream capacity and whether downstream pipelines can retain upstream capacity.

1. Priority for Bundled Sales Customers

UDC argues that the Commission must amend section 284.242 of the regulations to state affirmatively that firm sales customers of a pipeline have first priority to allocation of upstream transportation capacity formerly used to provide the pipeline's bundled sales service. It states this will reflect Order No. 636-A's statement that "customers of downstream pipelines

have priority access to upstream transportation and storage capacity."[92] UGI also argues that section 284.242 should be amended so that the phrase "without undue discrimination" does not compromise converting customers' priority rights in the allocation of all upstream capacity and storage.[93] UGI maintains that this right is necessary to continue the level of firm deliverability embedded in converting sales customers' prior sales contracts.

The Commission clarifies that current bundled firm sales customers of downstream pipelines have a priority right during the restructuring proceeding over other pipeline customers to upstream transportation and storage capacity to the extent that capacity is needed to maintain their pre-restructuring level of maximum daily entitlement to service. This is not an absolute right because there may be circumstances where upstream transportation or upstream storage or both are not necessary to maintain the downstream pipeline customer's level of maximum

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92. Order No. 636-A, at p. 30,568. UDC also states that "Order No. 636-A clarified that current bundled firm sales customers of pipelines have a priority right to upstream and storage necessary to maintain their level of maximum daily entitlement to service, whether or not they elect no-notice transportation service." Petition at 15. However, Order No. 636-A at the cited text referred only to downstream storage. Order No. 636-A at p. 30,578.

93. Section 284.242 provides as follows:

> An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on all upstream pipelines, whether the firm capacity is authorized under Part 284 or Part 157.

daily entitlement. This parallels the Commission's conclusions in Order No. 636-A that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service and that customers that converted earlier were able to do so without access to storage. If upstream capacity or storage is available after bundled firm sales customers elect their levels of capacity, the pipeline must offer and allocate the remaining capacity among all its shippers on a nondiscriminatory basis. That is, current system users other than bundled firm sales customers have no priority over new transportation customers for upstream transportation and storage capacity that is not selected by current bundled firm sales customers.

The Commission will not amend section 284.242 because this is a capacity allocation matter. The priority for bundled firm sales customers does not contravene the requirement that the downstream pipeline offer its upstream capacity without undue discrimination because the allocation priority is reasonable when necessary to preserve the bundled firm sales customer's level of pre-restructuring maximum daily entitlement upon conversion to unbundled service.

2. Retention of Upstream Capacity By Pipelines

The Commission previously denied requests that pipelines be permitted to retain capacity on their own systems downstream of the point of unbundling on their systems. ANR seeks rehearing of the Commission's statement that a downstream pipeline holding capacity on upstream pipelines may not perform a sales service at the interconnection with an upstream pipeline. It argues that a pipeline will be unable to compete with other merchants, that it will be precluded from selling gas

supply under contract, and will be forced to buy out marketable gas supplies with little or no leverage. It adds that its suppliers will demand the higher market price from ANR's former customers.

Natural refers to Order No. 636-A's prohibition on downstream pipelines holding capacity on upstream pipelines as properly interpreted to mean that a pipeline sales division cannot retain upstream capacity on a preferential basis. It is concerned that Order No. 636-A could be interpreted to preclude the pipeline sales division from holding any capacity on other pipelines upstream of the point of unbundling, which would freeze it out of access to significant supply areas during the restructuring proceedings.

UGI argues that the Commission should allow downstream pipelines to show that it is necessary for them to retain title to upstream capacity to meet their existing firm transportation obligations to their customers for both peak-day entitlements and quality of service. UGI maintains that the quality of service provided by Columbia Gas Transmission Company will likely be lower than it is now if Columbia must assign its over 80 interconnections with upstream pipelines on a piecemeal basis. Arkla contends that downstream pipelines should be able to retain title to, but not the use of, upstream capacity to provide greater flexibility to the pipeline.

The Commission adheres to its conclusion that downstream pipelines may not hold capacity on upstream pipelines to perform a sales service at the interconnection with an upstream pipe-line.[94] Pipelines, such as ANR and Natural, can still compete

94. As stated in Order No. 636-A, downstream pipelines can hold capacity on upstream pipelines in the production area. Order No. 636-A at p. 30,566.

with other merchants by selling, in the production area, gas supplies under contract or obtained in the future. Pipelines, as merchants, are not forced to buy out marketable gas supplies nor are they frozen out of significant supply areas. Natural's interpretation, that the Commission has prohibited only retention of upstream capacity on a preferential basis, is incorrect because that would permit a pipeline to sell gas at downstream interconnections with upstream pipelines. As noted earlier, a pipeline's marketing affiliate can obtain capacity on any pipeline.

As stated in Order No. 636-A, downstream pipelines can retain some capacity on upstream pipelines to the extent they demonstrate it to be necessary for operational management and balancing purposes and the performance of the no-notice transportation service.[95]

To the extent UGI's and Arkla's arguments involve operational concerns, they are case-specific. Hence, UGI and Arkla should raise their concerns in the relevant restructuring proceedings.

Of course, the Commission recognizes that, on some pipelines, operational problems could arise owing to the assignment of upstream capacity involving many interconnections and downstream customers. Hence, the parties to the restructuring proceeding are encouraged to develop innovative proposals to deal with this problem. For example, it may be adequate for the downstream customers to appoint an agent to arrange transportation for them as a group or they could take some form of joint title to the upstream capacity (*e.g.*, an undivided interest).

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95. Order No. 636-A at pp. 30,566-67.

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3. Relationship of Section 284.242 to Restructuring

Order No. 636-A stated that a downstream pipeline may reduce its upstream capacity "with the consent of the potentially affected customers of the downstream pipeline."[96] ANR maintains that one or two customers should not be able to refuse to consent and cause all customers to incur the cost of unneeded capacity so that the two can reserve capacity for possible future use. ANR suggests the Commission "impose a presumption that a customer's election not to receive a permanent assignment of capacity is deemed an assent by that customer to a capacity reduction or termination under section 284.14(c)(4)."[97]

The Commission denies ANR's request. The requirement of unanimity only pertains to consent to assignment or relinquishment of upstream capacity in the restructuring proceeding. It is necessary to ensure that customers of downstream pipelines have adequate opportunity to make their decisions about upstream capacity during the restructuring proceeding. Once the upstream pipeline completes its restructuring process, the downstream pipeline may release its Part 284 capacity under section 284.243 of the Commission's regulations without the consent of downstream customers. If that release is permanent, then it will not be available for the downstream customers to take assignment under section 284.242. If the release is not permanent, the downstream customer may exercise its section 284.242 rights, subject to the release.

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96. Order No. 636-A at p. 30,641. *See also id.* at p. 30,568.

97. Petition at 8.

4. Timing Of Implementation

Transco asks the Commission to clarify how and when the assignments under section 284.242 are to be accomplished. Transco maintains that it should be able to make those assignments to its shippers on a self-implementing basis prior to the effective date of its Order No. 636 compliance filing because section 284.242 became effective on May 18, 1992, and because Order No. 636 stated that "section 284.242 capacity reassignments '*must* be effectuated in the restructuring proceedings' prior to release of capacity under new section 284.243."[98] Transco further asserts that one upstream pipeline has notified Transco that the upstream pipeline interprets Order No. 636 to preclude the effectiveness of upstream capacity assignments until the restructuring proceedings are completed and that it would not consent to Transco's assignments until it received assurance that its service obligation to Transco was superseded by its service obligation to the shippers obtaining assigned upstream capacity. Last, Transco points out that the Commission has stated it will allow early implementation of certain aspects of Order No. 636, such as open access storage and capacity releasing.[99]

Brooklyn Union supports Transco's motion and argues that consent by upstream pipeline suppliers is not required to effectuate permanent assignments of upstream capacity and that, upon such assignment, the upstream pipeline's service

98. Motion for Clarification at 2, *citing* Order No. 636 at p. 30,417 n. 120.

99. *Citing* Northern Natural Gas Co., *et al.*, 59 FERC ¶ 61,362 at p. 62,363 (1992). *See also* ANR Pipeline Co., 59 FERC ¶ 61,205 at p. 61,724 (1992).

obligation to the downstream pipeline is replaced and superseded by its obligation to the new firm shipper.[100] Brooklyn Union maintains that, to effectively evaluate the available range of services, shippers need to know the full amount of upstream and on-system capacity available to them.

Natural responds that it supports upstream capacity assignments prior to full implementation of Order No. 636 by the downstream pipeline only if the upstream pipeline consents. It maintains this is necessary so that a downstream pipeline that has not complied with Order No. 636 cannot gain a temporary competitive advantage. Natural adds that an assignee of upstream capacity must meet the upstream pipeline's creditworthiness provisions as is the case for replacement shippers under section 284.243.[101]

Section 284.14(b)(i) of the Commission's regulations requires pipelines to make a compliance filing that, among other things, implements Subpart H of Part 284, including provisions to implement "assignment of capacity rights on upstream pipelines to firm customers."[102] Hence, assignments under section 284.242 are not self-implementing for the downstream pipeline; it must implement such assignments through its compliance filing with the Commission. This is necessary so the Commission can resolve any issues involving the appropriate allocation of capacity by downstream pipelines on upstream pipelines.

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100. Brooklyn Union's motion for leave to answer Transco's motion is granted.

101. Order No. 636-A at p. 30,558.

102. 18 CFR 284.14(b)(l)(xiv).

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The Commission will permit a downstream pipeline to make a compliance filing in its RS docket to implement its upstream pipeline capacity assignment prior to the effective date of other aspects of its compliance filing under Order No. 636. The downstream pipeline must include in its compliance filing its allocation methodology, including how it will take into account the rights of current bundled sales customers to upstream capacity.[103] Natural should raise its objections to early approval in response to the downstream pipeline's compliance filing.

Upstream pipelines do not have to file tariff provisions to implement section 284.242. However, they must permit the assignment, even if it is prior to the effective date of the upstream or downstream pipeline's compliance filing under Order No. 636. Because the assignee has met the downstream pipeline's creditworthiness requirements, the Commission sees no reason for it to requalify under the upstream pipeline's standards. In any event, the Commission has not been made aware of situations where upstream and downstream pipelines have significantly different creditworthiness requirements. The assignment of upstream capacity will result in a new transportation agreement under Part 284 between the upstream pipeline and the assignee.[104] Upon the effective date of that agreement, the contractual arrangement between the upstream pipeline and downstream pipeline is terminated and abandonment is authorized as stated in Order No. 636-A.[105]

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103. See Part C.1., *supra* with respect to the priority of current bundled sales customers to upstream capacity.

104. Even if the downstream pipeline held capacity on the upstream pipeline under Part 157, the transportation agreement between the assignee and the upstream pipeline will fall under Part 284. This will provide the assignees with the flexibility to fully utilize available sources of supply.

105. Order No. 636-A at p. 30,567.

Appendix D

D. No-Notice Transportation Service

In Order No. 636, the Commission required pipelines to provide a no-notice transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. Petitioners raise a variety of issues dealing with the availability of and eligibility to receive no-notice service.

1. Availability of No-Notice Service

In Order Nos. 636 and 636-A, the Commission concluded that a pipeline was required to offer a no-notice transportation service only to customers that were entitled to receive a no-notice, city-gate, firm sales service on May 18, 1992, and that pipelines are not required to offer a no-notice service to other customers because they have not been receiving such a service. The Commission encouraged the pipelines to offer a no-notice transportation service to all transportation customers on a non-discriminatory basis.

Northern States argues that the Commission erred by limiting required no-notice service to bundled, city-gate, firm sales customers under contract as of May 18, 1992. Northern States argues that it is necessary to offer no-notice service to all firm shippers to eliminate undue discrimination between classes of service. Prior Energy similarly argues that pipelines should be required to offer no-notice service to all shippers who wish to purchase it on an open access, non-discriminatory basis. Prior Energy contends this is necessary to avoid discrimination between customers by allowing customers who were also customers on May 18, 1992, to receive a service unavailable to anyone else.

The APGA also argues that the Commission erred in limiting required no-notice service to customers that were entitled to receive no-notice firm city-gate sales service on May 18, 1992. The APGA argues that other customers should be entitled to no-notice service, "subject to (1) the rights of pre-existing bundled sales customers and (2) limitation of facilities."[106] The APGA maintains that this is necessary because some customers may have declined more firm sales service because of the high cost of supplies or because facilities may have been completed but not approved. The APGA adds that this restriction may undermine the growth in the natural gas industry because LDCs will not be able to render incremental service on a reliable basis. The APGA maintains that a pipeline should bear a heavy burden of showing that it cannot provide incremental no-notice service because it lacks operational flexibility.

Southwest Gas and Indicated UtiliCorp Divisions argue that no-notice service should be offered to customers who previously converted to transportation to ensure comparability of service as envisioned by Order No. 436's policy that the quality and priority of service to a converting customer would be no lower than the quality of the prior sales service. [107]

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106. Petition at 7.

107. Southwest Gas cites Order No. 436, FERC Stats. & Regs. [Regulations Preambles] ¶ 30,665 at p. 31,517 (1985):

> Firm sales customers that convert their contract demand rights to transportation rights. . . will have the same priority of service under their converted transportation service as they did under their firm sales service agreements. There is no change in the quality

(Cont'd)

Southwest Gas adds that the Commission has arbitrarily changed its comparability policy which was reflected in the Commission's reliance on comparability in proposing this rule and in adopting no-notice service. It further argues that, in converting, customers relied upon continuation of the comparability principle to ensure no service degradation and that, on some pipelines (*e.g.*, El Paso Natural Gas Company), comparability concerns were yet to be resolved. Last, it maintains that reliability of unbundled transportation service via no-notice service is just as important to customers who converted prior to May 18, 1992.

The Commission denies rehearing. The Commission established the no-notice transportation service so that bundled, city-gate, firm sales customers can continue to receive service of the same reliability and quality in the unbundled environment as they received in the bundled environment. The Commission did not require pipelines to expand the eligibility for the no-notice transportation beyond those sales customers receiving no-notice service on May 18, 1992, for several reasons. First, because a stand-alone, no-notice transportation service is a new service, it is prudent to preserve only the status quo to allow pipelines to gain experience with its operation. Second, customers who were not receiving no-notice service (as part of their bundled sales service) on May 18, 1992, were not relying on that service because pipelines did not offer a no-notice transportation service. Third, those customers could not reasonably expect to receive no-notice service in the future. Order No. 436's requirement of service comparability, while broad, did not encompass no-notice firm transportation. Hence,

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or priority of their service, because the priority of their claim on the pipeline's capacity is unchanged by conversion.

the Commission did not change its comparability policy to the detriment of customers who converted prior to May 18, 1992. In addition, the Commission's Notice of Proposed Rulemaking (NOPR) did not explicitly propose no-notice transportation service. That service was required for bundled, city-gate, firm sales customers in the final rule in response to the comments to the NOPR and related technical conference held on January 22, 1992.[108] To conclude, the Commission required no-notice transportation service in response to a particular problem raised by petitioners *vis a vis* a particular service — no-notice bundled, city-gate, firm sales service. Nonetheless, the Commission strongly encourages the pipelines to make no-notice transportation service available to customers on a non-discriminatory basis to the maximum extent possible.

2. One-Time Election

In Order No. 636-A, the Commission concluded that pipeline sales customers have a one-time right to elect no-notice transportation during the restructuring proceeding. The APGA argues that this limitation is untenable because the pipeline's customers cannot make their decisions without knowledge of the Commission approved criteria and rates of no-notice service and without some practical experience. The APGA seeks clarification that "(1) a pipeline shall not require a binding and permanent election of no-notice service until after the pipeline's tariffs are made effective following restructuring; (2) customers electing no-notice service may alter their nominations prospectively under procedures set forth in the tariff."[109]

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108. Order No. 636 at pp. 30,408-09.

109. Petition at 9.

Similarly, the regulatory commissions of the states of Iowa, Missouri, and Wisconsin argue that it is impossible for LDCs to elect no-notice service until the Commission rules on the pipeline's compliance filing. They argue that the Commission should allow the free availability of no-notice service until system users have the experience to make informed choices.

The Commission continues to believe that the right to elect no-notice transportation must be exercised in the restructuring proceedings. The Commission recognizes that final elections on the precise levels of no-notice service may depend on the Commission's final disposition of the compliance filing, so that the final elections may need to be made after the Commission's order accepting the compliance filing. The Commission, however, will not require pipelines to provide the ability to elect new or added no-notice service after the effective date of restructuring. The purpose of no-notice transportation is to provide former bundled sales customers with continuity of service upon the effective date of the pipeline's compliance filing. Pipelines may, if they wish, permit their customers to switch between no-notice and other transportation services after the restructuring proceedings so long as this ability is available on a nondiscriminatory basis. The pipeline and the customer would execute a new contract for the different service and they would terminate the contract for the previous service. This is similar to the requirement that if a pipeline voluntarily offers no-notice service in the restructuring proceeding to customers other than those who qualify under the rule, it must do so on a non-discriminatory basis.[110]

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110. Order No. 636-A at p. 30,574.

Appendix D

3. Upstream Pipeline and Other Deliveries

The APGA and AGD ask the Commission to clarify that upstream pipelines will be required to provide a no-notice transportation service at the downstream pipeline delivery point. The APGA maintains that customers that qualify for no-notice service on downstream pipelines must be offered no-notice service on upstream pipelines, even if they have no direct customers that qualify for the service.

The Commission clarifies that upstream pipelines need to provide no-notice transportation service only to those customers to whom they provided no-notice service on May 18, 1992, and to the capacity assignees of those customers under section 284.242 of the Commission's regulations.[111] This is because it is reasonable to assume that a downstream pipeline that provided no-notice service without no-notice service from upstream pipelines can continue to provide no-notice service without requiring the upstream pipeline to serve the downstream customers on a no-notice basis. In short, the assignees of the downstream pipeline step into its shoes for this purpose when they take the capacity on the upstream pipeline.

New Jersey Natural contends that if a customer received firm no-notice sales service at a place other than its city gate, it should be entitled to receive no-notice transportation.

The Commission clarifies that an upstream pipeline that provided a no-notice sales service on May 18, 1992, to a

111. See Order No. 636-A at pp. 30,572-73, where the Commission's description of no-notice service to downstream customers assumes that they can succeed to any no-notice service held by the downstream pipeline on upstream pipelines.

customer that did not take delivery at its city gate must provide no-notice transportation to that customer at the non-city gate delivery point. This comports with the Commission's conclusion that customers receiving no-notice service on that date should have the right to maintain the no-notice aspect of their service. The Commission discussed no-notice service in the context of citygate service because that was the predominant no-notice service.

Brooklyn Union argues that it should be entitled to no-notice transportation regardless of whether it took its sales gas at its city gate from the selling pipeline or through an intermediary pipeline. It states that it purchases gas from certain pipelines that are not connected to its city gate with other pipelines transporting the gas to its city gate. It cites as an example its purchases from CNG Transmission Corporation that are delivered to Brooklyn Union's city gate by Transco and by Texas Eastern Transmission Corporation. UGI notes its concern that it cannot become a no-notice transportation customer on the upstream pipeline in lieu of the no-notice sales service it receives from Columbia Gas. UGI takes the Columbia Gas directly from Texas Eastern.

With respect to the scenario described by Brooklyn and UGI, where each bought gas from one pipeline but took delivery from another pipeline, the Commission interprets no-notice to mean that Brooklyn Union and UGI are entitled to no-notice service from the delivering pipeline (*i.e.*, Transco and Texas Eastern), if the delivering pipeline was contractually obligated to deliver the gas to them on a no-notice basis on May 18, 1992. However, whether Brooklyn Union or UGI is entitled to no-notice service on an upstream pipeline (*e.g.*, CNG) is an issue for the restructuring proceeding.

4. Option to Elect No-Notice or Traditional Transportation Service

In Order No. 636-A, the Commission concluded that "a sales customer, at its election during the restructuring proceeding, may choose no-notice or traditional firm transportation or a combination of the two."[112] CIG argues that the Commission erred by permitting former bundled sales service customers to choose their transportation services. CIG maintains that while the Commission recognized that no-notice transportation service was the appropriate substitute service for bundled sales service, it did not show that the firm transportation option is needed on all pipelines. CIG claims that this option is peripheral to the problem faced by the Commission and, therefore, improper.[113] In addition, CIG contends that it will lose the needed centralized coordination and control of its system if customers are permitted to elect traditional firm transportation service. It maintains that traditional firm transportation customers might adversely affect its system capacity, storage operations, gathering system, the thermal content of its gas, and transition costs. It asks the Commission to eliminate the traditional firm transportation option or alternatively reaffirm that pipelines can condition that service in a way that ensures operational control.

The Commission's intent in the instant rule is to afford former bundled sales customers a meaningful choice of transportation services best suited to their needs. In addition, no-notice service was established as an additional, or enhanced, form of firm transportation service and not as a service in lieu

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112. Order No. 636-A at p. 30,577.

113. *Citing* Associated Gas Distributors v. FERC, 824 F.2d 981, 1018-20 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

of traditional open access firm transportation service. Hence, while the Commission improved traditional open access firm transportation service (*e.g.*, storage and flexible delivery points), the Commission intended no-notice transportation service as an additional transportation option for no-notice sales customers.

The Commission reaffirms that pipelines may need to impose operational conditions on traditional open access firm transportation to perform no-notice transportation. The pipelines, of course, must propose those conditions in their compliance filings so that the Commission can evaluate them to determine if they are reasonable operational conditions under sections 284.8(c) to be applied without discrimination as required by section 284.8(b).[114]

5. Flexible Delivery Points

In Order No. 636-A, the Commission stated that pipelines must provide their no-notice transportation service at flexible delivery points. United argues that the Commission should eliminate this requirement because it will result in inefficient usage of the pipeline system and result in greater costs for no-notice shippers.[115] It adds that this requirement goes beyond the Commission's justification for no-notice service and the Commission's NGA section 5 authority to modify unreasonable contracts. It argues that the Commission has mandated a service clearly superior to the bundled, no-notice, firm city-gate, sales service provided on May 18, 1992. United

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114. See also the discussion of operational control in the discussion of storage, *infra*, Part E.2.

115. United refers to the cost of transmission and storage capacity reserved by it to provide no-notice delivery at any delivery point.

concludes that no-notice service beyond the delivery points specified on May 18, 1992, should be optional on a non-discriminatory basis.

Upon further reflection, the Commission will further clarify its position on the availability of flexible delivery points for no-notice service. Because no-notice service is limited to a discrete set of former sales customers and is intended to duplicate service provided under the pipeline's bundled sales service, a pipeline will not be required to provide flexible delivery points for its obligation to provide transportation, on a no-notice basis, without scheduling penalties. In other words, pipeline customers are entitled to no-notice service at their primary firm delivery points at the time they convert from bundled sales service to no-notice transportation service. The pipeline customers are not limited to their delivery points as of May 18, 1992. For example, a pipeline sales customer with delivery points A, B, and C pre-restructuring will retain those delivery points post-restructuring for no-notice service but will not be entitled to receive no-notice service at other primary firm delivery points or at secondary firm delivery points. Pipelines are free, however, to provide for flexible delivery points for no-notice service when operationally feasible.

One of the primary reasons the Commission required the provision of flexible delivery points was to facilitate capacity release of firm transportation capacity. No-notice service is a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. No-notice service, therefore, consists of two aspects: firm transportation and no-notice delivery. The releasing shipper can release its firm transportation capacity with the right to flexible delivery points. However, the no-notice

delivery aspect of its service pertains only to current delivery points as described above and not to flexible delivery points, which are part of the firm transportation aspect of its service.

6. Operational Flow Orders

In Order No. 636, the Commission stated that "pipelines have the right to impose reasonable operational conditions and to issue, on a non-discriminatory basis, operational flow orders without liability, except for negligence or undue discrimination, to be able to provide a no-notice transportation service."[116] New Jersey Natural asks the Commission to clarify that pipelines may not use operational flow orders to impose "must take" requirements on its customers. It maintains that "must take" requirements will subvert the efficiency goal of a competitive market if customers must take gas regardless of economic and market conditions. It adds that they may not be able to physically take the gas and that unmarketable gas would increase costs to their ratepayers and could harm their markets in the long run. It further contends that operational flow orders might require LDCs to take gas above their contractual obligations to pipelines and might undermine no-notice service by requiring LDCs to take gas instead of reducing takes below the nominated volumes without notice.

A pipeline may not issue an operational flow order that would require a shipper to ship gas above its reservation quantity. However, the Commission reaffirms that pipelines are entitled to impose reasonable operational conditions, including operational flow orders. The pipeline, therefore, can make its shippers inject gas into the system within their contract

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116. Order No. 636-A at p. 30,575.

quantities ("must ship" gas) when and where necessary to maintain the system's operational integrity and to enable the pipeline to provide no-notice transportation service. The Commission, as stated, will review the conditions proposed by pipelines to ensure they are reasonable and are nondiscriminatory. In addition, as no-notice service evolves, and experience is gained, the Commission expects to revisit the conditions in light of that experience. In particular restructuring compliance filings, the Commission will consider arguments that particular conditions are unworkable with respect to particular pipeline customers.

E. Storage

In Order No. 636, the Commission amended section 284.1(a) of the Commission's open access regulations to define transportation as including storage. This section deals with petitioners' contentions about allocation of the open-access storage capacity and the rights of existing holders of storage capacity.[117]

1. Allocation Of Downstream Storage Capacity

In Order No. 636-A, the Commission clarified Order No. 636 by stating that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service whether or not they elect no-notice transportation service. The Commission further stated that previously converted customers are not entitled to the same priority as customers converting under Order No. 636-A because

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117. Transco's request for clarification regarding unbundling at the outlet side of its Eminence storage field is an issue for its restructuring proceeding.

the former customers were able to convert without storage to meet their needs. In addition, the Commission stated that current system users are to have no priority over new transportation customers for any storage capacity available after converting customers exercise their priority right to storage.

The Indicated UtiliCorp Divisions argue that the Commission erred in denying guaranteed access to storage for previously converted sales customers. It argues that pipelines (such as Williams Natural Gas Company) used their storage to support their transportation customers on peak days and included storage costs in their firm transportation rate. It asks the Commission to clarify that, "unless a former sales customer expressly has relinquished its right to system storage capacity upon exercise of its conversion rights, it retains a priority right to that capacity."[118] It adds that the relinquishment issue should be left to individual restructuring proceedings.

The United Cities also argue that LDCs that previously converted to firm transportation should have priority rights to pipeline storage facilities. United Cities maintain that those customers have used the storage bundled within pipeline sales to meet swings in demand above their firm transportation base load. United Cities add that providing certain customers with "artificially high" pipeline storage capacity will cause the pipeline to operate below maximum efficiency. They claim this is so because those customers will use storage for the middle of their load profile, thereby reducing peak withdrawals.

Prior Energy objects to the priority for converting sales customers on the grounds that they may not value it as highly

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118. Petition at 7.

as other shippers, such as marketers. Prior Energy maintains that Order No. 636-A thwarts the goal of vigorous competition by relegating non-sales customers to a second-tier of storage claimants.

The Commission reaffirms its clarification in Order No. 636-A that only current bundled firm sales customers have a priority right to storage. Customers that have previously converted to firm transportation under Part 284 without contract storage are not entitled to a priority because they were able to receive their firm transportation entitlement level without any contract storage rights. A pipeline's use of system storage to support transportation service, and the allocation of storage costs to transportation, was not related to firm entitlement levels, but to operational management and balancing.[119] Pipelines may continue to reserve some amount of system storage for operational management and balancing to support traditional transportation services to customers, including previously converted customers, as well as no-notice transportation. The pipeline has the burden of showing what level of storage it needs to support its services.

The Commission's grant of priority to bundled sales customers to preserve service levels is necessary to ensure their certificated levels of service. "Value of service" concepts are not pertinent to this priority right to the storage.

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119. System storage includes facilities owned and used by the pipeline to store its own gas for operational reasons such as for balancing. System storage also has been used in lieu of transportation capacity to make bundled sales.

Appendix D

2. Existing Contract Storage Service

In Order No. 636-A, the Commission concluded that while current contract storage customers retain their full right to capacity as specified in their contracts, the terms and conditions associated with those rights could be changed, if they are unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage.[120]

AGD, Brooklyn Union, PSE&G, and UGI argue that the Commission has not justified why it is necessary to affect existing storage arrangements.[121] AGD contends that the Commission has offered no explanation about why a pipeline cannot use the same physical and operational assets that it uses to render no-notice sales service to provide no-notice transportation service. AGD, PSE&G, Brooklyn Union, and UGI maintain that a reduction in the quality of currently certificated contract storage could jeopardize an LDC's ability to serve its customers during peak periods. They ask the Commission to state that it will not permit changes to their contract storage service quality, such as adverse modifications to existing contract storage capacity and injection or withdrawal schedules. AGD and PSE&G maintain that any such degradation of service would be a *de facto* abandonment and would be inconsistent with the abandonment requirements of NGA section 7(b).

The Commission clarifies that, while it has authorized pipelines to propose to change existing storage arrangements,

120. Contract storage describes storage capacity with respect to which the customer can inject its own gas.

121. AGD and UGI argue similarly with respect to existing transportation service.

if necessary, to provide no-notice transportation service, the pipeline must still show that the changes are necessary and reasonable. This includes an analysis of the impact of a change on current contract storage customers. The Commission has not authorized any reduction in contract storage capacity. The Commission views changes to injection and withdrawal schedules as changes to terms and conditions, rather than changes to the level of certificated service. Hence, the Commission concludes that changes to existing contract storage terms and conditions will not need action under NGA section 7(b).[122]

F. Market Centers/Pooling Areas

In Order No. 636, the Commission adopted sections 284.8(5) and 284.9(5), which prohibit tariff provisions that inhibit the development of market centers. The Producer Associations, as a progress report, allege that long-line pipelines are proposing rate features that will make it uneconomical for gas suppliers attached to those pipelines to switch pipelines at a market center to serve markets on a different pipeline. They cite the following examples:

> Rate features such as "system access charges," a requirement that firm mainline transportation must be supplied by firm production-area transportation contracts, and GSR surcharges applicable to production-area transportation make it very difficult and expensive for gas suppliers to access markets through transportation on multiple pipelines.

122. The pipelines may change the terms and conditions of other services in a similar manner, if necessary to provide no-notice transportation.

> In addition, permitting pipelines to charge their forward haul rates for backhaul service has, on several pipelines, insulated markets from competition by off-system suppliers. Further, several pipelines have proposed transportation rates based upon the zone of the delivery point, irrespective of the length of haul. Such tariffs also have the effect of discouraging competition.[123]

NERCO contends that pipelines are developing proposals that limit pipeline-to-pipeline competition in the supply area and inhibit the creation of market centers and commercially useful pooling points. NERCO cites as an example the implementation of production area rates that are too low and the definition of access area to the mainline to include inputs that should be outside the area. NERCO asks the Commission to clarify on rehearing that "individual pipelines may not, in the course of the restructuring proceedings, implement production area rates and other onerous proposals that inhibit pipeline-to-pipeline production area competition and, thus, inhibit the creation of market centers and commercially useful pooling points."[124]

The Commission reemphasizes that pipelines may not implement rates (or terms and conditions of service) that inhibit the creation and development of pooling areas and market centers.

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123. Petition at 2, 3.

124. Petition at 14, 15. ConEd endorses NERCO's request.

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Market centers are areas where a) pipelines interconnect and b) there is a reasonable potential for developing a market institution that facilitates the free interchange of gas. The size of a given market center may depend on the specific configuration of the pipelines involved. However, the Commission expects generally that market centers should normally be fairly small — for instance, a 30-mile radius around a central point. In order to facilitate gas transactions, many market centers are likely to offer services that correct imbalances among pipelines (for instance, through storage).[125]

Rate structures can inhibit market centers when (for instance) they require shippers to pay for substantial amounts of capacity both upstream and downstream of a market center in order to use only the upstream or downstream part of the pipeline. Postage stamp rates and rates based on large zones can have this effect. Similarly, rates can inhibit market centers when a pipeline charges a large zone rate simply to transfer gas among two other nearby pipelines within a market center. In both cases, the result amounts to tying transportation services together that are commercially distinct and is contrary to the spirit of service unbundling. In addition, inappropriate rates for backhauls or penalties for scheduling and balancing can inhibit market center development. Either can prevent a shipper from using its capacity rights flexibly and inhibit the flexible commercial interchange of natural gas.

The Commission does not require pipelines to adopt any particular approach to ensure that they do not inhibit the

125. See, for example, illustrations of market centers in Importance of Market Centers, Office of Economic Policy, FERC (Washington, D.C.), August 21, 1992.

development of market centers.[126] However, the Commission reiterates that the effects of pipeline rates and terms and conditions of service on market centers and pooling areas should be resolved in individual restructuring proceedings.[127]

G. Flexible Receipt and Delivery Points

1. Small Customers

Prior Energy asks the Commission to clarify whether small customers are entitled to use flexible receipt and delivery points. Small customers are firm shippers under Part 284 of the Commission's regulations and therefore are entitled to flexible receipt and delivery points just as any other Part 284 firm shipper. Flexible delivery points, however, are of primary importance to facilitate capacity releasing. Since small customers paying one-part rates are not able to release capacity, the availability of flexible delivery points may be of only minimal value to them.

2. Penalties

In Order No. 636-A, the Commission concluded that "[i]ssues involving provisions governing the use of receipt and delivery points, including appropriate penalties, must be

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126. Depending on the pipeline configuration and operation, it may be possible, for example, to establish special zones for market centers, small zones or rates based on 100 mile increments, or separate "within market center" rates for hauls to and from interconnections within larger zones.

127. *See, e.g.*, El Paso Natural Gas Co., 60 FERC ¶ 61,109 (1992).

addressed in the restructuring proceedings."[128] The Commission added that "there must be some valid operational reason for imposing penalties on changes in volumes to delivery points within an interrelated service area."[129]

The Fuel Managers Association is concerned about unduly strict scheduling requirements and scheduling penalties. It asks the Commission to clarify that a pipeline must demonstrate affirmatively, through documented evidence submitted during the restructuring proceeding, that any proposed scheduling requirement or penalty mechanism is needed to address operational concerns on its system and why a less onerous scheduling requirement or penalty would not be sufficient to address its operational concerns. It maintains that a mere statement by a pipeline that it needs its scheduling requirements or penalties to inhibit abusive behavior should not satisfy its burden of proof.

The Commission grants the Fuel Manager Association's clarification and agrees that pipelines must demonstrate that their proposed scheduling requirements and penalty mechanisms are reasonable operational conditions. The Commission observes that scheduling requirements and penalties serve different functions. Scheduling requirements are needed to provide the pipeline with advance information to operate its system efficiently. Penalties are designed to inhibit behavior inimical to the operational integrity of a pipeline system.

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128. Order No. 636-A at p. 30,584.

129. *Id.*

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3. Deliveries Within a Zone

In Order No. 636-A, the Commission concluded as follows with respect to alternate flexible delivery points within a zone:

> [S]hippers with upstream delivery points within a zone can select downstream delivery points within the same zone and . . . operational concerns can be met by making service to the downstream delivery point interruptible. This is consistent with the general principle that controls here: a shipper gets flexibility in receipt and delivery points for the part of the system for which it pays a reservation charge. Thus, if a pipeline has zone rates, a shipper gets flexibility within its zone.[130]

New Jersey Natural argues that the alternate flexible firm delivery points downstream in a zone should have priority over the rights of interruptible shippers. It also seeks clarification that shippers on pipelines with postage-stamp transportation rates may designate downstream delivery points without restriction. It maintains that they should be able to do that because both upstream and downstream shippers are paying for access to the entire pipeline system.

The Commission's discussion, quoted above, was addressed to the relative rights only of firm shippers. Firm shippers with alternate flexible firm delivery points downstream in a zone have priority over the rights of interruptible shippers but not

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130. Order No. 636-A at p. 30,585.

over firm shippers with primary firm delivery points. Shippers nominating volumes for delivery to primary firm delivery points have scheduling priority over shippers nominating volumes for flexible (alternate) firm delivery points.

With respect to designation of downstream flexible delivery points, a postage-stamp system should be treated similarly to a zone system. Since shippers on a system with postage-stamp rates pay reservation charges covering the entire system, they may designate downstream alternative firm delivery points on the same basis as shippers within a zone. The Commission strongly encourages pipelines with postage stamp rates to consider developing smaller zones or mileage-based rates, particularly where such rate structures will foster the development of market centers.

4. Curtailments

The APGA seeks clarification with respect to the scenario where there is a capacity constraint in the path of firm transportation on behalf of shippers using primary and flexible delivery points. It maintains that since the service to alternate delivery points is interruptible, it should be curtailed prior to service to any primary delivery point.[131] It adds that this should be so whether the alternate delivery point is upstream or downstream of the primary delivery point.

The Commission clarifies that a pipeline must give

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131. The firm shipper selects primary delivery points, which are firm for scheduling purposes, and secondary or alternate delivery points, which do not have scheduling priority over primary delivery points of other firm shippers but have scheduling priority over delivery points of interruptible shippers.

scheduling priority to shippers using primary delivery points if there is a capacity constraint when, for example, a compressor is malfunctioning. That is, the shipper scheduling for an alternate firm delivery point is treated as interruptible for scheduling purposes in this situation.[132] If the constraint develops after gas is scheduled, service to alternate firm delivery points should be considered just as firm as service to primary firm delivery points.

V. Transportation Rates

In Order Nos. 636 and 636-A, the Commission adopted the SFV method of cost classification for cost allocation and rate design (billing) purposes, required the use of different measures to mitigate cost shifts, and required pipelines to continue to serve small customers at a one-part rate computed using an imputed load factor. Petitioners raise a variety of issues with respect to the mitigation measures and the treatment of small customers.

A. Different Ratemaking Techniques

In Order No. 636-A, the Commission stated that "it will require the parties to use different ratemaking techniques in connection with the distribution of revenue responsibility among customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand."[133] The Commission strongly encouraged the use of seasonal contract quantities (*i.e.*,

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132. Scheduling service at the alternate firm delivery points is, of course, superior to scheduling interruptible transportation. Order No. 636 at p. 30,583.

133. Order No. 636-A at p. 30,599.

seasonal entitlements or CDs) as a means to counteract those shifts and as a replication, in part, of the allocation of costs based on peak and annual considerations. The Commission permitted the parties to explore other methods.

1. Opposition to Different Ratemaking Techniques

Several petitioners oppose the use of different ratemaking techniques to mitigate significant cost shifts. In particular, they oppose the use of seasonal contract quantities or annual volumes as the mitigation technique.

Allied-Signal objects to the using of different ratemaking techniques to avoid significant cost shifts owing to SFV because in its view the customer class phase-in method, the capacity adjustment and releasing mechanisms, and the use of a one-part volumetric rate at an imputed load factor for small customers provide all the mitigation necessary. The Industrial Groups similarly argue that firm customers can mitigate via capacity releasing and alternatives such as peak shaving, storage, and conservation.

The Commission believes that the Order No. 636-A mitigation measure is superior to the methods referred to by Allied-Signal. It is broader based than the treatment afforded small customers and historic customer classes in that it mitigates for all customers which face a significant cost shift. Moreover, it ensures mitigation as part of the ratemaking process rather than relying solely on the possibility that capacity can be released or other measures implemented. Finally, the Commission in the past has used ratemaking approaches (such as imputed load factors and annual nominations) that recognized that customer load factors vary.

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Allied-Signal, the Industrial Groups, Sierra Pacific, Louisville, and LILCO maintain that the use of seasonal contract quantities or techniques based on annual volumes will have a variety of undesirable impacts. For example, they argue that such mitigative techniques will be inefficient with respect to such matters as customer load factors, patterns of pipeline usage, storage acquisition and use, and capacity releasing. The Commission concludes it is premature to speculate as to the generic impact of seasonal contract quantities or other mitigation measures. Petitioners may raise their contentions about impact in specific restructuring proceedings when the issue is joined, and where arguments can be linked to the specific circumstances of the pipeline and its particular customers.

The Industrial Groups argue that the end result of mitigation is a welfare-type subsidy for low load factor customers while Louisville argues that seasonal contract quantities are an inequitable subsidy because they hurt residential customers of LDCs who have undertaken load factor improvement efforts. The Commission believes it is appropriate to minimize significant cost shifting that may occur among customers so that the impact of SFV, to aid competition as discussed in Order Nos. 636 and 636-A, is not distributed inequitably among the shippers on the interstate pipeline network. The Commission does not consider this to be an unfair "subsidy," because it does no more than maintain the status quo with respect to the relative distribution of revenue responsibility.

The Industrial Groups and Allied-Signal maintain that seasonal contract quantities will undermine or distort SFV's price signals. Sierra argues that seasonal contract quantities undermine the Commission's goals in that they will improperly affect a gas customer's choice about its gas seller. It maintains

that this will result because the demand charges on different pipelines will be determined based on seasonal demands. It points out that on pipelines with identical costs the demand charges will differ because they have a difference in seasonal demand.

The Commission sees no adverse impact on price signals or improper impact on a gas purchaser's choice of gas sellers stemming from the use of seasonal contract quantities or similar measures because the pipeline's reservation charge will still be billed under the SFV method. In addition, that seasonal contract quantities will produce different reservation charges on pipelines with identical costs is a fact entitled to no weight. That situation is just as likely to occur without seasonal contract quantities because it is unlikely that two pipelines would have identical reservation quantities with daily reservation quantities applicable throughout the year. In addition, it is highly unlikely that any two pipelines would have identical costs.

Sierra further argues that this mitigation approach is inconsistent with Commission policy that transportation rates are to reflect allocative and productive efficiency. It maintains this is because seasonal contract quantities encourage demand on peak days and penalize off peak use.

The Commission did not adopt SFV to promote allocative and productive efficiency in the use of pipeline capacity.[134] Rather, it adopted SFV, as fully discussed in Order Nos. 636 and 636-A, to promote the goal of an efficient, national gas market by allowing all gas merchants to compete equally without regard to fixed transportation costs included in the pipeline's

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134. Order No. 636-A at p. 30,605.

usage charge. The Commission's decision to require pipelines to implement ratemaking techniques to eliminate cost shifts resulting from the change to SFV does not interfere with this goal because the usage charge for firm transportation would be unaffected by any such ratemaking techniques. In any event, the lower usage charge under SFV should enhance productive efficiency by promoting gas on gas competition, reducing transportation usage rates and encouraging increased throughput.

Sierra maintains that, in effect, there is no difference between the D-2 charge and seasonal contract quantities. It adds that seasonal contract quantities reintroduce the problems associated with D-2s, such as how they are chosen and whether renominations will be allowed. It argues that Order No. 636-A makes implementation problems more severe by making it difficult to predict needs. It also maintains it is unclear what effect a customer's seasonal contract quantity will have on the pipeline's certificate obligation.

Seasonal contract quantities are different from, and in the Commission's judgment, superior to the manner in which D-2 charges operated. D-2s did not reduce the firm customer's daily entitlement, while seasonal contract quantities do place a contractual limit on capacity rights. D-2s also did not permit the pipeline to sell unsubscribed firm off-peak capacity, while seasonal contract quantities would permit such sales of unsubscribed off-peak firm capacity. The Commission believes that the issue of how seasonal contract quantities are chosen is an issue for the restructuring proceedings.[135] As with no-notice

135. That is, pipeline customers do not have a unilateral right to seasonal contract quantities. However, a pipeline that does not want to have seasonal contract quantities must develop another methodology to address potential significant cost shifts, as discussed in Order No. 636-A.

service, this election should be made during the restructuring proceedings. Pregranted abandonment under section 284.221(d) of the Commission's regulations is granted to the extent there are reduced seasonal quantities. The parties to the restructuring proceedings should address the issue of whether shippers should have renomination rights after a pipeline's restructuring becomes effective.

LILCO maintains that seasonal contract quantities will enable pipelines to collect excess revenues associated with uncommitted capacity from which it can collect interruptible transportation revenues. The Commission sees the interruptible revenue issue raised by LILCO as no different than the allocation of costs to interruptible service ordinarily faced by the Commission.[136]

Sierra argues that the use of seasonal contract quantities is merely a cost-shift mechanism that has no relationship to how costs are incurred. The Industrial Groups argue that facilities are built to meet peak demands and that off peak usage adds only variable costs. Hence, they maintain, any technique based on annual factors would allow customers to escape cost responsibility.

The Commission stated in Order No. 636-A that it adopted SFV because the pro-competitive goals to be accomplished via SFV generally outweigh the ratemaking principle of allocating fixed costs to annual throughput. However, the Commission required adjustments in connection with the distribution of revenue responsibility among customers to avoid significant

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136. See the discussion of this issue in the capacity releasing part of this order, *supra*.

cost shifts among pipeline customers resulting from varying load profiles.

The Commission believes it is appropriate to recommend the use of seasonal contract quantities to mitigate significant costs shifts that may occur in individual cases because the use of annual or similar factors is a well-settled method of distributing revenue responsibility among pipeline customers that will not conflict with the goals to be achieved via SFV by retention of a one-part reservation charge for billing purposes.

Southwest Gas asks the Commission to clarify that (except for two-part demand charges) it will permit any variety of either entitlement-based allocation methods (*e.g.*, seasonal or maximum daily entitlements) or demand-based allocation methods (*e.g.*, coincident peak demand). At this time, the Commission is not prohibiting any particular techniques except, as discussed below, that two-part demand charges may not be used for billing purposes.

Southwest Gas seeks clarification about whether allocation methods to reduce cost shifting are to be applied uniformly to all customers. Since the extent of cost shifting and the application of any ratemaking technique is dependent on the circumstances facing each pipeline, the Commission cannot make a generic determination of this issue. Parties in the individual restructuring proceedings should consider and develop the ratemaking methodology best suited to reducing the cost shifts for each pipeline.

To conclude, the Commission adheres to its conclusion that pipelines must "use different ratemaking techniques in connection with the distribution of revenue responsibility among

customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand."[137] The Commission believes it is appropriate to "minimize significant cost shifting" among customers,[138] so that the impact of adopting SFV to aid competition as discussed in Order Nos. 636 and 636-A is not distributed inequitably among the shippers of varying load profiles on the interstate pipeline network. The Commission also continues to strongly encourage the use of seasonal contract quantities to mitigate significant cost shifts that may occur owing to the adoption of SFV. However, the Commission recognizes that it may not be appropriate in all circumstances to use seasonal contract quantities and encourages creativity in the tailoring of mitigation techniques suited to the specific facts of each case. Hence, the Commission will not, as requested by the APGA, adopt a presumption favoring the use of seasonal contract quantities.

2. Meaning of Significant Cost Shifts

Several petitioners ask the Commission to define significant cost shifting. Allied-Signal maintains that at a minimum this means a ten percent or more rate impact of SFV on any customer class. The Industrial Groups would define a significant increase as over ten percent. The Producer Associations would also apply the 10 percent threshold. Sierra argues that all costs (transportation, storage, and gas costs) reflected in the delivery price of gas to the pipeline's customer must be considered.

The Commission clarifies that all transportation costs (*i.e.*,

137. Order No. 636-A at p. 30,599.

138. *Id.*

costs allocated to transmission, including system storage retained by the pipeline) are to be considered in applying the "significant" cost shift test.[139] The delivered cost of gas is irrelevant to the impact of SFV on a customer's transportation costs. In addition, this test is to be applied by customer rather by customer class.[140] However, the Commission declines to set a bright-line test for determining "significant" cost shifts because this depends heavily on the facts of each case. The only bright-line test occurs at the end of the restructuring ratemaking process when pipelines must phase-in cost shifts over no more than a four-year period, if the use of SFV, *after* implementation of other ratemaking techniques designed to minimize cost shifts, still results in a 10 percent or greater increase in revenue responsibility for any historic customer class.

Allied-Signal argues that the use of different ratemaking techniques should be used to mitigate the significant impact of SFV and not to eliminate all cost shifts by putting customers into the same revenue position as they were under MFV. Similarly the Fuel Managers Association contends that mitigation must not create cost shifting to high load factor customers by over-mitigating the cost shift to low load factor customers caused by SFV. The Commission clarifies its goal is

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139. In addition, if the pipeline used MFV to design its contract storage rates, it must determine if the use of SFV will result in a significant cost shift for existing contract storage customers. However, if the rate design for contract storage did not change, then it need not be included in determining whether significant cost shifts will occur.

140. Northwest Pipeline Corp. 61 FERC ¶ 61,165 (1992), United Gas Pipeline Co., 61 FERC ¶ 61,161 (1992), Alabama-Tennessee Natural Gas Co., 61 FERC ¶ 61,164 (1992), Mississippi River Transmission Corp., 61 FERC ¶ 61,163 (1992), and Pauite Pipeline Co., 61 FERC ¶ 61,162 (1992).

to avoid significant cost shifts resulting from the change to SFV and not to provide an opportunity for some customers to make themselves better off at the expense of other customers.

3. Phase-Out

The Industrial Groups contend that any ratemaking techniques used to avoid significant impacts should be phased out over the four-year transition period. Sierra also argues that these measures should be transitional, as were D-2s, and not permanent.

The Commission clarifies that there is to be no automatic phase-out period for any technique used to avoid potential significant shifts in the assignment of revenue responsibility. The Commission will examine the appropriateness of the assignment of revenue responsibility in future NGA section 4 or 5 cases. Customers can file complaints under NGA section 5 for Commission reconsideration of the lawfulness of effective rates and the underlying method for distributing the revenue requirement.

4. Seasonal Capacity Availability and Seasonal Rates

The Fuel Managers Association argues that pipelines must make available, on an open access basis, any seasonal firm capacity that becomes available through the use of seasonal contract quantities.

Similarly, Blue Flame argues that the pipelines should be able to offer services that take advantage of seasonal demands for gas from special use customers. Blue Flame maintains that the Commission should not have discouraged the creation of

customer classes, [141] which limits pipeline services to firm peak-day transportation, interruptible transportation and the small customer transportation services.

The Fuel Managers Association also argues that the Commission should clarify that the use of seasonal rates is particularly important to encourage the use of capacity in non-winter periods that becomes available because of the use of seasonal contract quantities. It is concerned that pipelines will have little incentive to discount rates if all costs are allocated to existing customers.

Sierra argues that any seasonal allocation to address shifts in revenue responsibility must reflect cost incurrence with costs classified between winter and summer seasons and then allocated based on seasonal demands to yield winter and summer reservation charges.

The Commission clarifies that it has put no limit on the current ability of pipelines to offer firm transportation service in any particular circumstance. Part 284 pipelines have always been and remain required to offer all firm capacity that becomes available. This will include capacity that becomes available through the use of seasonal contract quantities,[142] subject to any operational constraints.

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141. Blue Flame refers to the statement in Order No. 636-A that "as a general matter, the Commission discourages the creation of customer classes, other than the special small customer class provided for in this rule, or if necessary during the four year mitigation period." Order No. 636-A at p. 30,599-60.

142. *See* Northern Natural Gas Co., 61 FERC ¶ 61,079 (1992) (approving rate schedule under which shippers can transport on a seasonal basis).

The Commission will not require seasonal rates.[143] Seasonal rates are not related to the instant rule's goals or to the mitigation of significant cost shifts.[144] As indicated in Order No. 636-A, it may be appropriate to apply the principles enunciated in the Rate Design Policy Statement in determining whether seasonal rates are appropriate.[145] The Commission will consider the Fuel Managers Association's argument about the incentive to discount in connection with a particular case involving off-peak service.

5. Annual Allocation Measures

In Order No. 636-A, the Commission concluded that pipelines may not continue to use two-part reservation charges for either allocation or billing purposes.

The APGA asks the Commission to clarify that pipelines and their customers may use D-2 charges, if D-2s serve the purpose of distributing revenue responsibility among customers to avoid significant cost shifting. The APGA maintains that D-2s may be the best solution to cost shifting on certain pipelines.

CIG argues that a two-part demand charge does not undermine the Commission's policies in adopting SFV, because the charge is not based on usage but is assessed on the basis of peak entitlements regardless of actual volumes transported. CIG

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143. Seasonal entitlements differ from seasonal rates in that seasonal entitlements may yield one rate applicable throughput the year. See Order No. 636-A at p. 30,599 n. 308 for an example.

144. See Order No. 636-A at p. 30,606 with respect to cost incurrence and the instant rule.

145. *Id.* at p. 30,605.

adds that a two-part demand charge might be appropriate if a pipeline, like CIG, cannot provide maximum service entitlement levels throughout the year. It asserts that this would properly reflect cost incurrence. CIG further argues that a two-part reservation charge is consistent with the mitigation of cost shifts and is superior to seasonal contract quantities, because on its system temperature fluctuations occur throughout the year.

Southwest Gas argues that the Commission should permit D-2 charges because they are not a usage based charge. It adds that the end-result should determine the reasonableness of any approach.

The Commission concludes again that pipelines may not use two-part reservation charges for billing. It is true that the D-2 charge is not a usage charge in the sense that customers pay as they take service. However, the D-2 charge is similar to a usage charge in that the D-2 charge was to reflect demand for annual service in light of estimated use. In any event, the D-2 charge was derived, in part, to help pipelines in their role as merchants by enabling them to better estimate customers' annual gas purchases. In the competitive sales market with competitive pricing mechanisms for unbundled gas sales, which may include some type of gas inventory charge, the D-2 is no longer needed. Seasonal contract quantities also reflect the fact that a pipeline cannot provide maximum service levels throughout the year by allowing lower off-peak levels. That there are temperature fluctuations throughout the year does not militate against seasonal contract quantities. Rather, it suggests the use of monthly contract quantities, which the Commission encourages the parties to pursue in the restructuring, or subsequent, proceedings.

However, pipelines may use annual measures for cost allocation so long as only a one-part reservation charge is used for billing purposes. As stated in Order No. 636-A, the Commission will not foreclose the use of any annual measures as a vehicle for allocating revenue responsibility (*e.g.*, among rate zones) so long as the pipeline uses a one-part reservation charge for billing purposes and does not create different charges in the tariff for individual customers because of the use of D-2s or other annual allocation measures.[146] The Commission is permitting the use of annual measures because they may be the most appropriate method for certain cost allocations (*e.g.*, among rate zones) to avoid significant shifts of revenue responsibility.

Last, CIG states that its annual service limitations predate the Commission's adoption of the modified fixed variable method, have been negotiated based on operational constraints, and are incorporated in its certificates. Hence, it seeks clarification that the adoption of a one-part reservation charge does not affect its annual service limitations.

The Producer Associations argue that if the Commission allows fixed cost allocation based on D-2 nominations, customers should pay higher rates for taking deliveries over their nominations and should not be allowed to release capacity in excess of the nominated level. Similarly, Allied-Signal argues that, if annual volumes are used as a mitigation technique, there should be some restriction on the ability of a customer to demand service above its annual level without penalty.

The Commission clarifies that a pipeline may retain some form of annual service limitation post-restructuring in connection

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146. Order No. 636-A at p. 30,595 n. 287.

with a one-part reservation charge, as long as the annual service limitation does not operate as a D-2 charge. Furthermore, nothing in this rule obligates a pipeline to provide service in excess of its pre-restructuring certificate obligations. In any event, this issue is unrelated to the rate design issues addressed in Order No. 636.

6. Capacity Reduction

Meridian argues that SFV should only be adopted if the pipeline is capacity-constrained or full unless the customers are permitted to reduce or terminate their service unilaterally.

In Order Nos. 636 and 636-A, the Commission denied the right of customers to unilaterally reduce or terminate transportation service from the pipeline. The Commission also, as discussed in Order No. 636-A, did not apply the policy of adopting a rate design to ration capacity because in "the prevalent economic and market circumstances, . . . the goal of achieving an efficient, national gas market is the factor that should control the selection of appropriate rate design method."[147] Hence, Meridian's argument is rejected.

B. Rates for Small Customers

In Order No. 636-A, the Commission clarified that all pipelines that on May 18, 1992, offered a small customer sales or transportation rate service on a one-part volumetric basis at an imputed load factor rate must continue to offer firm and no-notice transportation services on the same basis. The

147. Order No. 636-A at p. 30,605. *See also* Order No. 636-A at pp. 30,637-38, where the Commission concludes that customers do not have the unilateral right to cost-free releases of capacity.

Commission also suggested pipelines should consider increasing the class of small customers by raising the eligibility level to up to 10,000 Mcf or Dth per day.

1. The Use of an Imputed Load Factor

Peoples Gas, the Northern Distributor Group, and Atlanta Gas argue that there is no basis for the Commission's requirement that pipelines continue indefinitely to offer small customers a one-part volumetric rate at an imputed load factor. They argue, among other things, that this results in two shippers paying different rates for the same service and is therefore discriminatory. They also argue it is unfair because large LDCs serve customers in poorer communities in large urban areas and serve communities that are smaller than the pipeline's small customers.

The Northern Distributor Group argues that, as provided in Order No. 636, imputed load factor rates for small customers should only be used as a transitional measure to be phased-out within four years. It asserts that this will adequately protect small customers against cost shifts. It also maintains that the use of imputed load factors results in a subsidy which does not serve equality or competitiveness. It adds that the requirement that the rate be changed only in an NGA section 4 or section 5 proceeding will have a chilling impact on changes because the burden will be on the proponent of change and that the pipeline will have little incentive to change the rate because it is recovering its costs. It concludes that either the rate should be negotiable in the restructuring proceedings or prior settlements should remain in effect. In that vein, it contends that a settlement

with Northern Natural Gas Company contemplated the eventual elimination of one-part rates.[148]

The Commission's aim with respect to service to small customers is to continue the status quo prior to the instant rule, subject to the few changes in terms and conditions adopted in this Rule. While some petitioners read Order No. 636 to mean that service to small customers at a one-part rate was to be continued only in connection with phased-out mitigation, that was not the Commission's intent. Arguments that the small customer rate should be discontinued should be raised in pipeline proceedings under NGA sections 4 or 5.[149]

On the other hand, the APGA argues that the Commission erred in failing to make the one-part rate design for small customers, as well as other ratemaking techniques employed to moderate the impact of SFV, a permanent rate design requirement for pipelines.[150] In the alternative, the APGA asks the Commission to rule that any changes to the one-part rate design can only be made prospectively under NGA section 5 rather than under NGA section 4, subject to refund.

The Northern Distributor Group argues that the use of a

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148. Northern Natural Gas Co., 53 FERC ¶ 61,207 at p. 61,835 (1990). The rate was for a three-year period ending September 30, 1993.

149. The Commission has, however, incorporated parts of pending proceedings with respect to rate design issues, which include one-part rate matters, into restructuring proceedings. Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

150. The temporal status of the other ratemaking techniques is discussed in other sections of this order.

small customer imputed load factor rate should be phased-out within four years.

As indicated above, the one-part rate design for small customers was continued because the Commission did not intend to change it in this rule. It is no more or less permanent than any rate design and may be changed under sections 4 and 5 of the NGA. Because the one-part rate design for small customers is a continuation of the status quo, it is not subject to phase-out under the instant rule.

2. Adjustments to Imputed Load Factor

In Order No. 636-A, the Commission stated that the pipeline's one-part, volumetric rate for its small customer service should be computed using the same imputed load factor as was used to compute its previous rate for its small customer sales service.

CIG seeks clarification that it can propose to adjust the imputed load factor to reflect changes in the load factor of small customers caused by Order No. 636. It maintains that this may be necessary to ensure that the imputed load factor does not substantially exceed the actual load factor.

The Gas Consumers argues that the Commission should require pipelines to derive their one-part rates using the system-wide load factor. It maintains that this is necessary to mitigate cost shifts, which is not done by using the class load factor. It asserts that a Commission mandate is sought because small customers lack the leverage to bargain for such a load factor.

The Northern Distributor Group argues that pipelines should

be allowed in their compliance filings to propose lowering their current imputed load factor for small customer rates.

As stated above, the Commission intends no change in its current policies with respect to the small customer rate.[151] This includes retention of the imputed load factor used to compute the rate for the small customer sales service unless there is warrant for increasing the imputed load factor as a measure to avoid shifts in revenue responsibility. However, the imputed load factor may not be decreased in the restructuring proceedings.[152]

3. Eligibility Date

In Order No. 636-A, the Commission required pipelines that, on May 18, 1992, offered a small customer sales or transportation service at a one-part volumetric rate, with an imputed load factor, to offer all of its firm transportation services on the same basis to eligible small customers.

The Gas Consumers argue that the Commission's justification for the use of one-part rates applies equally to all customers with peak capabilities of less than 10,000 Mcf per day, regardless of whether they were charged previously under one-part rates with imputed load factors. The Gas Consumers

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151. The only mandatory exception relates to restrictive criteria needed to ensure the pipeline has the opportunity to recover costs assigned to the small customer service. For example, the small customer must exhaust its daily level of firm entitlement before shipping gas under any interruptible transportation service available from the pipeline.

152. An exception would exist when the issue has been raised in a rate proceeding that has been incorporated into the restructuring proceeding. *E.g.*, Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

maintain that if the Commission grandfathers the one-part rate, it should do so with respect to all pipelines that ever offered service at a one-part rate to small customers, because many pipelines have replaced their one-part rates with two-part rates. Hence, it states, that, on May 18, 1992, most small customers that had received service under a one-part rate for years were receiving service under a two-part rate. The Northern Distributor Group argues that the small customer class should not be open to customers new to a pipeline system after May 18, 1992, to avoid further subsidies, which prevent unfair competition.

The Commission clarifies that, if a downstream pipeline offered service at a small customer rate on May 18, 1992, it must offer it to all customers directly connected to it who meet its eligibility criteria, even if such a customer was not a customer at that rate on May 18, 1992. The Commission's intent in Order No. 636-A was to grandfather service at the small customer rate to a particular class of customers and not particular customers.[153] That is, if the pipeline had a small customer rate schedule on May 18, 1992, it must retain that schedule and offer service thereunder to all customers who qualify. If a pipeline had discontinued all service at its small customer rate on May 18, 1992, and the Commission has approved of that discontinuation, it need not reinstate it because small customers were not relying on it.[154] As discussed below, there may be different considerations for customers of downstream pipelines that take assignments of capacity on upstream pipelines.

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153. Order No. 636-A at p. 30,600.

154. In response to Gas Consumers' comment, the Commission notes that a majority of pipelines currently offer small customer service using a one-part rate.

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4. Upstream Pipelines

The APGA seeks clarification about the transportation rate to be paid by small customers which acquire upstream capacity under section 284.242 of the Commission's regulations. It maintains that the small customers charged a one-part rate by the downstream pipeline for transportion should also be charged a one-part rate by the upstream pipeline for upstream transportation. The APGA adds that the upstream pipeline must charge the one-part rate to one-part customers of downstream pipelines, even if the upstream pipeline has no direct customers that qualify for that rate.

TVMGA asks whether a pipeline that offered such a service on May 18, 1992, must offer the similar service to a small customer that was not receiving the small customer service on May 18, 1992. It maintains that this is important to small customers of downstream pipelines which will be taking service on upstream pipelines.

The Commission will not require upstream pipelines without a small customer service on May 18, 1992, to institute a small customer service to provide a small customer rate for transportation to small customers on downstream pipelines which, under section 284.242, are receiving an assignment of upstream transportation capacity held by the downstream pipeline. However, if an upstream pipeline had a small customer service on May 18, 1992, the issue of whether it should provide a one-part transportation rate to small customers receiving an assignment of upstream capacity should be considered in the restructuring proceeding. This will enable the parties to consider the small customers' need for such a service on the upstream pipeline and the impact of the additional small customers on

the rates charged to the upstream pipeline's current customers under the small customer schedule and its customers paying a two-part rate.

5. Eligibility Criteria

In Order No. 636-A, the Commission stated that eligibility criteria for the small customer rate service would be based on existing criteria.[155] CIG states that one such standard is that eligible entities must be LDCs or municipally-owned gas systems. It asks the Commission to clarify whether CIG can retain this standard and exclude non-LDCs and non-municipalities (*e.g.*, producers and marketers) in the new small customer transportation rate schedule. Consolidated Minerals, a direct customer of Florida Gas Transmission Company, argues that pipelines should be required to offer the small customer mitigation measure to all customers using small quantities of gas, whether or not they were jurisdictional customers. Interstate Power asks for clarification that the small customer rate be based only on service criteria in the rate schedule and not on the status of the customer, whether it is an LDC or a municipal utility.

As stated, the Commission's intent was not to modify eligibility criteria, except as needed to ensure that the pipeline recovers its costs. Hence, the Commission has made no change to the pipeline's service criteria, including its criteria with respect to the nature of the customer. A direct customer, therefore, would be eligible only if eligible under existing criteria, unless the parties to the restructuring proceeding otherwise agree.

In Order No. 636-A, the Commission required pipelines to

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155. This is other than the new criteria set forth in Order No. 636-A, relating to interruptible service and released capacity. *See infra.*

consider enlarging the size of the small customer class to include any customer with the right to transport up to 10,000 Mcf or Dth per day on a firm basis in order to mitigate the effect of shifting to SFV on small customers who do not currently qualify for a pipeline's small customer rate schedule. The Commission stated further that whether the small customer class should be so enlarged on a specific pipeline is an issue to be considered by the parties in the specific restructuring proceedings.

Atlanta Gas argues that the Commission has offered no justification for requiring pipelines to enlarge the size of the small customer class to include any customer with the right to ship up to 10,000 Mcf per day on a firm basis. It objects to the Commission's explanation that this will mitigate cost shifts caused by SFV as not reasoned.

Prior Energy argues that the Commission's definition of small customer, as one who ships no more than 10,000 Mcf or Dth of natural gas per day, will enable far too many shippers to qualify. It would permit only customers who at present qualify as small customers on each pipeline to keep that status.

Blue Flame also contends that the Commission erred in finding it appropriate to increase the size of the small customers class up to 10,000 Mcf or Dth per day. It asserts this will shift more costs to the usage charge and have an adverse impact on wellhead prices. It maintains that the use of seasonal reservation quantities will adequately treat undue cost shifts and that further mitigation for small customers is an undue preference.

Peoples Gas also opposes increasing the class of small customers as suggested by Order No. 636-A because it will simply increase their subsidy.

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The Commission believes that the issue of whether a particular pipeline should increase the size of the small customer class up to 10,000 Mcf or Dth per day should be addressed in the restructuring proceedings. If necessary, the Commission will examine the issue on the merits, which will, among other things, enable the Commission to examine the extent of any cost shift to the non-small customers and to consider whether such an increase is so pervasive as to have an adverse impact on achieving the goals of the instant rule. In response to Blue Flame, the Commission observes that, unlike seasonal contract quantities, the one-part rate enables the small customers to match payments with receipt of service.

In Order No. 636-A, the Commission imposed two restrictions on eligibility for service at the small customer transportation rate. These were that the shipper cannot ship gas under any interruptible transportation service available from the pipeline and cannot ship gas as a replacement shipper under the capacity releasing mechanism of section 284.243 of the Commission's regulations unless the customer has exhausted its daily level of firm entitlement for that day.

Tenneco argues that additional restrictions are needed. It maintains that "no other shipper should be permitted to use the small customer's delivery point(s) as secondary points under a firm agreement, and small customers must be prohibited from receiving gas at their delivery points from an [interruptible transportation] shipper."[156] Tenneco claims that unless this loophole is closed "a small customer could circumvent the Commission's restrictions by simply buying gas from a third party shipper at its delivery point and receiving the difference

156. Petition at 9.

between the shipper's transportation and its own [firm transportation] rate through the price it would pay for the gas."[157]

The Commission's clarifies that its intent was that small customers receiving service at the small customer rate must first use the pipeline's firm transportation under the small customer rate schedule to provide the pipeline with the opportunity to recover its costs assigned to that service. Tenneco's argument comports with the Commission's interpretation of its regulations because it would prohibit evasion of the pipeline's firm transportation under the small customer service. A small customer should not be able to receive gas from third parties at the small customer's delivery points unless the small customer has exhausted its daily level of firm entitlement for that day in the aggregate.

Elizabethtown argues that the Commission should eliminate the condition that it (and others) cannot have access to interruptible transportation on Tennessee Gas Pipeline Company's (Tennessee) system at the same time it is using its small customer firm transportation service. Elizabethtown states that it must use interruptible transportation to avoid incurring penalties for exceeding its maximum annual quantity for firm service. Elizabethtown's argument is case-specific and should be raised in the Tennessee restructuring proceeding so that the Commission can determine, in acting on Tennessee's compliance filing, whether good cause exists to grant relief to Elizabethtown.

6. On-going Proceedings

Section 284.14(b)(3)(iv)(A) provides that a pipeline that must offer the small customer service must do so "on the same

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157. *Id.*

basis and under the same eligibility criteria as the small customer sales or transportation rate under the pipeline's last-approved tariff provisions for those services."

FMNGA states that on May 18, 1992, Florida Gas Transmission Company was billing its small customers on a two-part rate that is subject to refund and to the outcome of a hearing and a final Commission order yet to issue.[158] Florida Gas' proposed two-part rate was designed to recover the same revenue as the one-part rate contained in its last approved tariff. FMNGA asks the Commission to require Florida Gas to serve its small customers under either (1) the last-approved small customer rate or (2) a small customer rate that is at least as favorable as the rate treatment small customers were receiving as of May 18, 1992, even though the rate may not be a one-part rate based on an imputed load factor.

Atlanta Gas argues that the gas subsidy issue is being challenged on certain pipelines such as Southern Natural Gas Company and so the Commission has erred by deciding the merits of cases subject to on-the-record adjudications, without due process of law. It adds that deferring the resolution of the issue to a new rate proceeding is no answer.

The Commission has required Florida Gas to include as part of its compliance filing in Docket No. RS92-16-000 tariff sheets that offer firm transportation service on a one-part volumetric basis to customers presently serviced under Florida Gas' small customer rate schedule.[159] FMNGA should raise its

158. *See* Florida Gas Transmission Co., 56 FERC ¶ 61,180, *order on reh'g*, 57 FERC ¶ 61,171, *order denying reh'g*, 57 FERC ¶ 61,376 (1991).

159. Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

issues about Florida Gas' treatment of small customers in Florida Gas' restructuring proceeding.

The application of the generic determinations will be decided in the specific restructuring cases, with respect to the continuation of small customer rate schedules.

C. Miscellaneous Issues

1. Choice of Rates

The Municipal Gas Authority of Georgia asks whether small customers have the option to select one-part rate treatment or a two-part rate structure with seasonal billing determinants or some similar measure. It is concerned that on some pipelines it might be argued that seasonal billing determinants or some similar measure are not needed to comply with Order Nos. 636 and 636-A, if the pipeline simply offers a one-part firm transportation rate to small customers. It argues in support that it cannot compete for interruptible industrial load with interruptible transportation rates or with released capacity. In addition, it maintains it cannot accept two-part SFV rates without seasonal-type billing determinants. It describes this as a no-win situation, which provides no motivation for small customers to reduce any unnecessary contract entitlement or pursue industrial load. It asks the Commission to require the pipelines to provide a two-part rate structure with seasonal billing determinants for small, low load factor customers, whether or not such billing determinants are established for larger customers, as an option in lieu of one-part rates.

The Commission clarifies that the requirement that pipelines continue to offer service to their small customers at the one-part

rate, computed using an imputed load factor, and the requirement that they mitigate for significant cost shifts that may occur are independent. If a small customer wants to switch to a two-part rate, it may do so. The pipeline would then have to adopt measures to avoid a significant shift in revenue responsibility due to the switch to SFV, but not due to the loss of the imputed load factor.

2. Phasing-In Cost Shifts

In Order No. 636, as modified by Order No. 636-A, the Commission directed pipelines to phase-in cost shifts, if the use of SFV, *after* implementation of other ratemaking techniques designed to minimize significant cost shifts, still results in a 10 percent or greater increase in revenue responsibility for any historic customer class. This bright line mitigation measure is to phase-in any such rate increase over no more than a four-year period.

Southwest Gas seeks clarification about whether a class consists of all those customers under a particular rate schedule or those customers served under a particular rate schedule within the same rate zone. It refers to the order in *El Paso Natural Gas Co.*, as unclear.[160] There, the Commission stated that it "intended pipelines to perform mitigation measures by rate schedules within specific zones and not just by zones" as unclear.[161] In the alternative, it asks whether the definition of class is to be determined on a case-by-case basis.

Southwest Gas also asks for clarification that the mitigation

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160. 60 FERC ¶ 61,228 (1992).

161. *Id.* at p. 61,768.

for 10 percent or greater cost shift applies only to those customers within a class or classes that meet the bright line test.

The definition of class is to be determined on a case-by-case basis. However, contrary to Southwest, the mitigation measures required to be phased-in apply to the entire class, not to individual customers. Last, in response to the APGA's suggestion that this should be a permanent measure,[162] the Commission reaffirms that this mitigation measure is transitional and not permanent. This is because it relates to historic classes, some of which will no longer exist after unbundling is fully implemented.

3. Rates for Part 157 Transportation

In Order No. 636-A, the Commission stated that pipelines must charge the same rates for individually authorized NGA section 7(c) (Part 157) transportation and for Part 284 transportation and that it will permit individually authorized transportation rates to be so designed. However, the Commission stated that a party may raise any objection to that design in the restructuring proceeding.

Arkla objects to Part 157 shippers paying the same rates as Part 284 shippers for two reasons. First, it maintains that Part 157 transportation will, after restructuring, be inferior to Part 284 transportation (*e.g.*, the former is not permitted to participate in capacity releasing or have flexible receipt and delivery points). Second, it asserts that most individual transportation arrangements are economic only because of the negotiated

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162. The APGA also includes other mitigation measures in its argument that the rate for service to small customers should be permanent.

specific contract rates. It adds that Part 284 rates would unduly deprive the parties of the benefits of their bargains.

JMC Power Projects argues that the application of SFV rates to Part 157 shippers without capacity releasing is capricious.

The Commission clarifies that it intended only that rates for Part 157 transportation may be designed under SFV, with any appropriate mitigation.

The Commission did not mean that a pipeline had to charge the same reservation rate to both Part 157 transportation customers and Part 284 transportation customers. For example, an incremental reservation charge under Part 157 could be higher than a Part 284 reservation charge, even though both are designed under SFV. The application of SFV rates to Part 157 shippers is reasonable without capacity releasing because those shippers are entitled to mitigation to avoid significant shifts in revenue responsibility by customer and to the phasing-in of cost shifts of ten percent or greater for an historic customer class in connection with the application of SFV.

4. Contract Rates

Mojave asks for clarification about whether it must adopt SFV when it has contractually agreed to the use of a rate design inconsistent with SFV. It states that while its filed rates are designed under MFV, its contracts provide for rates that put both return on and of equity in the usage charge. The Indicated Shippers respond that this issue is *sui generis* to Mojave and should be addressed in its restructuring proceeding where they

plan to address it.[163] The Commission agrees with the Indicated Shippers that this issue (of the effect of SFV on existing contracts), should be resolved in individual restructuring proceedings so that the Commission can be informed fully about the facts and circumstances pertaining to those contracts and the positions of all parties.

The Producer Associations ask the Commission to clarify on rehearing that the "pipeline cannot use two-party negotiations to defeat the procompetitive policies represented by the Commission's adoption of an SFV rate design."[164] They are concerned about agreements between shippers and pipelines that specify MFV and about most favored nations clauses in some transportation agreements. The Commission reiterates that "it will carefully consider arguments for and against deviations from SFV, with the advocates against SFV bearing the burden of persuasion."[165] In addition, as further stated in Order No. 636-A, "[a]t a minimum, opponents of SFV must demonstrate that SFV is not needed to effectuate the goals of Order No. 636."[166]

5. Demand Charge Credits

In Order No. 636-A, the Commission concluded that the

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163. The Indicated Shippers' motion to file an answer out-of-time to Mojave's request for clarification and answer is granted.

164. Petition at 5.

165. Order No. 636-A at p. 30,605.

166. *Id.*

issue of whether pipelines should be required to provide demand charge credits during service interruption or curtailment, to provide an incentive to expeditiously restore service, should be resolved in individual rate proceedings because it does not pertain to Order No. 636.[167]

AGD argues that the imposition of an SFV rate design methodology justifies addressing this issue because it inseparably links firm service and demand charge payments. AGD also maintains that, by not allowing this issue to be considered in the restructuring proceedings, the Commission may have given pipelines unfair bargaining leverage. Last, it contends that the Commission has acted inconsistently with its prior treatment of this issue in *Northern Natural Gas Co.*, where it required the pipeline to give curtailed firm customers demand charge credits.[168] ConEd similarly argues that the Commission should address this issue in the restructuring proceedings because it is linked to SFV.

The Commission denies rehearing because it believes that this issue pertains to a demand charge designed under any rate design and is not so intimately related to SFV or any other provision of Order No. 636 as to require treatment in a restructuring proceeding.

6. Impact of Order No. 636 on Incremental Rates

In Order No. 636-A, the Commission stated the following about the impact of Order No. 636 on vintage pricing:

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167. *Id.* at p. 30,607.

168. 57 FERC ¶ 61,105 at p. 61,408 (1991).

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> Great Lakes Transmission Limited Partnership (Great Lakes) requests clarification that equal transportation on even terms requires the elimination of vintage pricing in favor of a uniform, market-based rate for comparable transportation services (constrained by the pipeline's highest cost-based tariff rate applicable to such services). The Commission will address this issue in Great Lakes' own proceedings concerned with vintage pricing rather than here or in the restructuring proceeding.[169]

Great Lakes and TransCanada ask whether the vintage issue is to be explored in Docket No. RP91-143, which is to deal with other issues with respect to implementing the incremental rates mandated for certain of Great Lakes' new services.[170]

The Fuel Managers Association asks the Commission to clarify that, during the restructuring proceedings, it will consider "whether a pipeline's use of incremental facilities would, as a result of restructuring, (a) justify rolled-in rate treatment for the incremental facilities or (b) require other mitigation measures in such matters as cost allocation or rate design to obtain fair and equitable treatment for incrementally-priced customers." [171]

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169. Order No. 636-A at p. 30,608.

170. Great Lakes Transmission Limited Partnership, Opinion No. 367, 57 FERC ¶ 61,140 and, Opinion No. 368, 57 FERC ¶ 61,141 (1991), reh'g pending of both opinions. The motions of Northern, Texas Eastern Transmission Corporation, and Natural to answer the requests for clarification by Great Lakes and TransCanada are granted.

171. Petition at 9. They describe as benefits the additional line pack (Cont'd)

The Commission agrees that issues with respect to the impact of the instant rule on so-called "vintage pricing" on Great Lakes should be addressed in Docket No. RP91-143. This issue is currently before the Commission and will be considered with the rehearing petitions of Opinion Nos. 367 and 368 and is not to be considered in Great Lakes' restructuring proceeding.[172] Further, to the extent the Commission has not previously acted on other rolled-in/incremental issues, they may be addressed in the restructuring proceedings.

7. Processing Rights

The Producer Associations argue that the Commission should adopt a generic policy applicable to all Part 284 pipelines engaging in gas processing and suggests the adoption of proposed language dealing with credits and other issues related to processing. The Commission will not use this rulemaking as a vehicle for adopting specific generic language with respect to gas processing since the rulemaking was not intended or designed to adopt generic rules or policies pertaining to gas processing except that the Commission, generally supports the principle that rates for processing should be unbundled from other services.[173] Further, the Commission has not received comment on the proposed language from other parties.

(Cont'd)
which may aid in the providing of no-notice service and the facilitation of releasing of aggregated capacity caused by increased pipeline capacity due to expansion.

172. Great Lakes Gas Transmission Limited Partnership, 57 FERC ¶ 61,140 and ¶ 61,141 (1991).

173. Order No. 636-A at p. 30, 609 ("[T]he Commission repeats its strong preference for fully unbundled services").

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VI. PIPELINE SALES

In Order No. 636, the Commission issued blanket sales certificates to open access pipelines authorizing firm and interruptible sales for resale at market-based rates. On rehearing of Order No. 636, the Commission modified Order No. 636 to require pipelines to continue to sell gas to their current small sales customers at a rate that is cost-based for a transitional one-year period.[174]

On rehearing, CNG asks the Commission to clarify that pipelines may impose take-or-pay obligations, minimum bills, one-part demand charges, or other reasonable terms to compensate the pipeline for acquiring the supplies needed to provide sales service to small customers. Further, CNG asks the Commission to condition small customer access to interruptible transportation and released capacity on the customer's satisfaction of its daily level of gas purchases from the pipeline. CNG asserts that small customers will have many options to secure supplies and that pipelines should not be compelled to secure supplies for one year without the small customers incurring some reciprocal obligation to purchase gas from the pipeline, or, at a minimum, compensate the pipeline for standing ready to serve. CNG notes that the Commission recognized the need for mutuality when it addressed small customers' transportation rates and conditioned small customers' access to released capacity and to interruptible transportation on a small customer's exhaustion of its daily levels of firm service entitlement for the day, and that the Commission should treat small customer sales similarly.

The Commission will not impose any minimum take

174. Order No. 636-A at p. 30,600.

requirements on the small customers and will not condition their access to released capacity or interruptible transportation on exhaustion of daily purchase requirements. The purpose of providing a transition period for small volume customers is to provide those customers with an opportunity to adjust to purchasing at negotiated prices and to gain experience in dealing with other suppliers. Requiring the small customer to meet minimum purchase requirements would defeat the purpose of this provision.

The transitional sales rate should not impose a significant burden on the pipelines. The provision is temporary and will be in effect for only a brief, one-year period. Moreover, by definition, the customers purchasing under this rate will be taking small volumes and the supply impact on the pipeline should be negligible. If a pipeline believes that the supply impact on its system will be substantial, it may address this issue in its restructuring proceeding.

For these same reasons, the Commission will not authorize the pipelines to reinstitute a minimum bill for small customers for the transition period. The pipelines have no minimum bill today and the transition period merely maintains the status quo for small customers.

The pipelines will be able to recover the gas costs associated with providing this service, but may not do so through minimum take or minimum bill requirements. The pipelines should address in the restructuring proceedings other proposals for cost recovery.

PGT asks the Commission to clarify that Order No. 636-A does not preclude cost-based sales rates for other customers as

well as small customers. PGT notes that in the NOPR, the Commission specifically indicated that pipelines could chose between cost-based or market-based rates,[175] but that Order No. 636 does not specifically address this issue. PGT also refers to the statement in Order No. 636-A that the Commission expects that pipelines will terminate their PGA mechanisms and initiate market based pricing of gas in order to remain competitive in the sales market,[176] but that pipelines are not prohibited from negotiating cost-tracking systems with their customers.[177]

The Commission clarifies that the blanket certificates authorize the pipelines to negotiate sales rates with their customers, and nothing in the rule prohibits the pipelines and customers from agreeing to rates that are based strictly on costs or, for that matter, any other basis. However, the Commission will not establish specific cost-based rates for gas sales for the parties and will not design a specific mechanism for gas cost recovery. This is a matter for negotiation between the parties. Because the Commission has decided to allow the parties to negotiate gas sales prices, the Commission will not engage in the same kind of regulatory oversight and review that it has used with the PGA mechanisms for the review of gas sales prices. The Commission intends to concentrate its regulatory focus on the transportation aspects of the pipeline's business. However, as the Commission explained in Order No. 636,[178] the parties to the restructuring proceedings may seek to prove that adequate

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175. IV FERC Stats & Regs ¶ 32,480 at pp. 32,559 - 32,560 (1991).

176. Order No. 636-A at p. 30,651.

177. *Id.* at 30,651 n.473.

178. Order No. 636 at p. 30,441.

divertible supplies of gas do not exist with respect to a particular pipeline and, if the parties sustain the burden of proof on this issue, the Commission will engage in more active regulation of that pipeline's sales.

VII. PIPELINE SERVICE OBLIGATION (AFTER RESTRUCTURING)

In Order No. 636-A, the Commission modified Order No. 636 to provide that in exercising the right of first refusal to retain capacity, the long-term firm transportation customer must match the price offered by a competing bidder, up to the maximum just and reasonable rate, and the longest contract term, up to a maximum period of 20 years. The requests for rehearing[179] object to the Commission's determination that capping the bidding at 20 years is an appropriate balance of the pipeline's need for stability and the customer's need for flexibility. In addition, UDC and UGI Utilities argue that the Commission should exempt from pregranted abandonment all firm shippers with contractual waivers of pre-granted abandonment. LILCO and APGA ask the Commission to require pipelines to accept the highest bid for capacity, even if the bid is below the maximum rate.

A. Length of Contract Term

The parties argue that the 20-year cap on the bidding adopted by the Commission does not reflect the comments of the parties, does not remedy their concerns, does not address

179. Requests for rehearing on this portion of the rule were filed by AGA, AGD, ConEd, Interstate Power, Utilicorp Divisions, Northern States, Peoples Gas, PSE&G, UGI, UDC, Washington Gas, State Commissions, NJBRC, Industrial Groups and Consolidated Minerals.

pertinent facts raised by the parties, is not supported by record evidence, and, therefore, is arbitrary, capricious, and not reasoned decisionmaking. These parties note that the majority of commenters asked for a cap on the bidding at a term of five years, others asked for a cap of three to ten years, but no one suggested the 20-year cap adopted by the Commission. In addition, they assert that the Commission has not addressed their concern that LDCs cannot accurately forecast their needs so far into the future nor answered their argument that this bidding requirement will in fact limit competition, contrary to the goals of the rule, by denying LDCs the flexibility to respond to changing market conditions.[180]

Further, the parties state the Commission has failed to respond to the contention that this bidding requirement tips the balance in favor of unregulated producers and marketers and will encourage speculation in pipeline capacity. Consolidated Minerals argues that under the rule, large shippers will reserve space on constrained pipelines to repackage it, and thus will determine who will have access to the pipeline.

In addition, State Commissions argue that the Commission failed to explain why long-term needs should have priority over short-term needs, and Interstate Power argues that the Commission failed to address its concern that these long-term contracts will not withstand state prudence reviews. People's Gas and UGI argue that this provision, coupled with the SFV rate design, will give pipelines no incentive to maintain or improve service.

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180. State Commissions note that the Department of Energy has recently sought comments on the effect of long term contracts on competition for natural gas. Notice of Inquiry, 57 Fed. Reg. 38182 (August 21, 1992).

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AGD and Interstate Power assert that there is no record evidence to support the Commission's rationale that 20 years has been the traditional length of service contracts in the industry. Further, several parties assert that the examples given by the Commission of such long-term contracts [181] are not representative of industry practice because these contracts support construction, and new projects generally require long-term agreements to support financing arrangements.

The Commission denies rehearing on this issue. The parties have misunderstood the purpose of the bidding cap and how the Commission expects the cap to function. Various parties have suggested that the Commission cap the bidding at one to ten years because they believe that to be an appropriate contract length for them in the current environment. The Commission, however, will not select the contract term for the parties. The purpose of the rule is to permit the market to determine contract terms, including duration. Therefore, the Commission capped the bidding at what it believes to be a reasonable outer boundary which still permits flexibility. The Commission is not requiring 20-year contracts and does not expect 20-year contracts to become the norm. Rather, the Commission capped the bidding at the outer, reasonable edge in order to give the market maximum flexibility to work within reasonable bounds. A firm shipper will have to commit to a 20-year contract only if a competing bidder values the service sufficiently to bid the maximum period.

Indeed, it is inconsistent that some petitioners argue that

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181. The Commission cited Pacific Gas Transmission, 56 FERC ¶ 61,192 (1991) and Iroquois Gas Transmission System, 53 FERC ¶ 61,194 (1990), *reh'g granted in part and denied in part*, 54 FERC ¶ 61,103 (1991) as examples of 20-year contracts. Order No. 636-A at p. 30,631 n.437.

the 20-year contract cap is too long while at the same time they express concern about security of supply in obtaining long term capacity. There is, of course, always a risk and an element of uncertainty in any forecast of future needs. LDCs are not unique among gas users in this regard. The Commission does not believe that LDCs are at a disadvantage with respect to other gas users in predicting future needs when exercising the right of first refusal. It is the Commission's judgement, based on industry practice, and in view of the types of contracts cited in Order No. 636-A,[182] that 20 years is a reasonable accommodation between the interests of stability and flexibility and provides a workable framework for market determinations. It is the Commission's judgement as well that the 20-year cap is a reasonable balance between ensuring that capacity is allocated to shippers that most value it and the LDC's need to maintain security of supply through capacity entitlements. However, if all the parties to a pipeline's restructuring proceeding agree to a different number of years for the contract cap, then the Commission will allow it.

UtiliCorp Divisions argue that the Commission does not give adequate weight to the presumption in favor of continued service or to the danger that the pipelines will use monopoly power to extract non-price concessions from the LDCs. Therefore, it concludes, the Commission has failed to adequately address the basis of the remand in *AGA II*, that the Commission has not explained how pregranted abandonment trumps another precept of regulation, *i.e.*, the protection of consumers against monopoly power through the refusal of service at the end of the contract period. Industrial Groups argue that there may be instances where continued service for a short term is in the

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182. Order No. 636-A at 30,631 n.437.

public interest, but the procedure adopted here does not afford parties the opportunity to explain the relevant circumstances.

As the Commission has explained, the right of first refusal procedure affords protection to the existing customer against any exercise of monopoly power.[183] The existing customer can always continue to receive service if it matches a competing bid. If there is no competing bid, the existing customer can always continue to receive service for any period it chooses by agreeing to pay the maximum rate. It is not contrary to the public interest to require customers to match the longest term bid to continue to receive service — especially where there is a reasonable cap on what constitutes the longest term bid. As the Commission explained in Order No. 636-A, long-term contracts generally benefit the system as a whole because they provide stability and benefits to all customers,[184] and section 7 of the NGA does not require the Commission to examine the particular circumstances of each case.[185] The right of first refusal procedure guarantees that existing customers may have continued service, while allowing market forces to play a significant role in determining the contract price and term.

B. Contractual Waiver of Pregranted Abandonment

In Order No. 636, the Commission stated that the pregranted abandonment provisions would not apply to conversions that

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183. Order No. 636-A at p. 30,631.

184. Order No. 636-A at p. 30,630.

185. Mobile Exploration and Production Southeast, Inc. v. United Distribution Companies, 111 S. Ct. 615 (1991).

took place during the period that the stay of pregranted abandonment under Order No. 500-J was in effect.[186] In Order No. 636-A, the Commission clarified that it would not expand the exemption from the pregranted abandonment provisions beyond those conversions that took place during the time the Order No. 500-J stay was in effect and stated that specific contracts that contain a waiver of the right to pregranted abandonment should be examined in the restructuring proceedings and not in this generic proceeding.

On rehearing, AGD and UDC argue that the Commission erred in deferring the examination of specific contractual waivers of pregranted abandonment to the restructuring proceedings. These parties argue that they won this protection through difficult negotiations and should not be required to fight this battle again during restructuring. UGI argues that the voluntary waiver of pregranted abandonment completely eliminates the legal and theoretical basis for requiring that capacity subject to these contracts go through the right of first refusal process in order to avoid pregranted abandonment. The parties ask the Commission to affirm, generically, that existing rights to waiver of pregranted abandonment will remain unmodified.

As the Commission explained in Order No. 636-A, the exemption from pregranted abandonment for conversions that took place during the Order No. 500-J stay is based on the Commission's decision in that proceeding and the resulting expectations of the parties.[187] It is appropriate, therefore, to clarify in this proceeding that those conversions will not be

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186. Order No. 636 at p. 30,452.

187. Order No. 636-A at 30,636.

subject to pregranted abandonment. Further, as a general matter, the parties may resolve issues in Commission proceedings by contractual agreements or settlements, and the Commission generally favors the resolution of issues by settlement. However, the Commission will not rule on the viability of any current settlements or contractual agreements in whole or in part, on a generic basis. The relationship between the provisions of existing settlements or agreements and the provisions of this rule will have to be examined on a case-by-case basis. This rule is not intended to affect existing valid waivers of pregranted abandonment, but the Commission will not rule on any specific waiver provisions here.

C. Bids Below the Maximum Rate

In Order No. 636-A, the Commission clarified that pipelines are not required to discount transportation rates under the rule and that if a lower bid is not acceptable to the pipeline, then the shipper is entitled to continued service at a rate between the minimum and the maximum negotiated by the shipper and the pipeline.[188] LILCO, APGA, and Meridian ask the Commission to require pipelines to accept the highest bid for capacity made available as the result of the bidding process at the termination of the contract. LILCO states that if pipelines are not required to accept offers at less than the maximum rate, then they will be able to refuse offers for discounted service and seek recovery of the costs associated with the unwanted capacity from their remaining customers through a section 4 filing. To prevent unnecessary cost shifts, LILCO argues, the Commission should grant rehearing and require pipelines to accept bids at less than the maximum rate where there are no other offers for capacity,

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188. Order No. 636-A at p. 30,629.

or forbid pipelines from recovering the cost of unwanted capacity from other shippers.

APGA and Meridian argue that unless pipelines are required to accept the highest bid, the market will not, in fact, determine the rate. APGA asserts that captive LDCs will have little leverage to negotiate if pipelines can reject a rate below the maximum. Meridian asserts that while the procedure set forth in Order No. 636-A may work on capacity-constrained pipelines, it will not work on pipelines where capacity is not fully utilized. Moreover, Meridian argues, since the bid that is received reflects the market value of the capacity, that is the rate and term that should be matched by the existing shipper. Meridian asks the Commission to clarify that where a pipeline refuses to accept a bid below the maximum rate, the pipeline, and not the customers, is at risk for any shortfall.

The Commission will not require pipelines to discount transportation rates. However, if a pipeline fails to attempt to maximize throughput, there is no guarantee that it will be able to recover all the cost of its underutilized capacity from its firm customers when it files its next rate case.[189] Evidence that a pipeline refused to accept the highest valued bid for capacity below the maximum rate will be given significant weight during its next rate case.

Meridian believes that the rule does not require the pipeline to reveal that a below maximum bid, or no bid at all, was offered for the capacity and asks the Commission to clarify that pipelines must post the highest bid actually received (or the fact that no

189. *See* Order No. 436, Regulation of Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Stats. Regulations Preambles 1982-1985 ¶ 30,665 at p. 31,523.

bid was received). The rule does not explicitly require pipelines to post competing bids on the bulletin board. However, it was the Commission's intent that the existing shipper have notice of the terms of all competing bids. The Commission clarifies that the pipeline must inform the existing shipper of the maximum bid received or the fact that no bids were received on the EBB. Moreover, the pipelines are required to publish in their tariffs the criteria they will use to determine the "best bid."

Meridian also asks the Commission to clarify that the previously effective rate should remain in effect during the period the pipeline and the customers are negotiating the terms for continued service. The Commission will grant the clarification.

VIII. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

A. Capacity Adjustments During Restructuring

Under section 284.14(e) of the Commission's regulations, firm shippers (including currently bundled sales customers) must give notice to the pipeline during the restructuring proceeding whether they wish to retain, reduce, or terminate their contractual rights to firm transportation service. The pipeline is authorized to abandon firm transportation service to the existing shipper if another creditworthy shipper offers to pay for the capacity an existing shipper wants to release, or offers to pay a higher rate (up to the maximum rate) than the existing shipper is willing to match, or the pipeline consents to the abandonment even though no other shipper makes an offer for it. Several parties reiterate concerns with issues already addressed in Order No. 636-A or request clarification of certain issues. The Commission will deny

the requests for rehearing but clarify certain issues as discussed below.

1. Unilateral Right to Reduce or Terminate CD

Meridian asks that existing capacity holders be given a unilateral right to reduce or terminate their contract demand (CD) during the restructuring proceedings. Meridian argues that, facing the prospect of an SFV rate design, shippers should be given the choice to reduce their contract demands or terminate their service agreements, thereby returning capacity to the pool and making it available for assignment to others willing to assume the costs and risks associated with SFV-based rates. Meridian asserts that, under section 284.14(e)(2) of the regulations, a firm customer paying the maximum rate is effectively trapped on pipelines where there is insufficient demand for capacity to be relinquished. Meridian recognizes that the pipeline might have to increase the demand charges of the customers with continued interest in firm service in order to afford relief to those who reduce or terminate their capacity reservations.

Cincinnati Gas contends that Order No. 636-A should be revised to impose an obligation on pipelines, in cases where there are no bidders for particular capacity during the restructuring process, to enter into good faith negotiations with the current capacity holder for the purpose of agreeing to a rate reflective of the capacity's actual worth. If such negotiations do not result in an agreement on an acceptable rate, Cincinnati Gas argues that shippers should be allowed to release the capacity, and that any costs associated with such releases should be treated as stranded costs.

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The Commission has already considered and rejected proposals like Meridian's and Cincinnati Gas' in Order No. 636-A.[190] In order to afford unilateral relief to firm customers that want to reduce or terminate their capacity reservations, or reduce their rates for capacity during restructuring, before their contractual obligations for the capacity have expired, the costs allocated to rates for the capacity in question would have to be absorbed by the pipeline or reallocated to other firm customers who may have no current need for the capacity. The parties are, of course, free to negotiate capacity allocation matters during the restructuring proceedings.

2. Expiration of Bundled Sales Contracts During Restructuring

UtiliCorp Divisions asks a question arising from the restructuring proceeding of Williams Natural Gas Company, where it indicates that certain sales customers have executed contracts that expire when superseded by another contract, or November 1, 1993, at the latest. UtiliCorp Divisions ask whether a current firm capacity holder with a contract that terminates on or prior to the date of restructuring, *i.e.*, the effective date of the pipeline's tariffs to comply with Order No. 636, may retain capacity following restructuring by agreeing to pay the pipeline's maximum rates and freely select the term for the first post-restructuring contract, or must also match the duration of a contract bid by potential new customers for that capacity. UtiliCorp Divisions argue that historic customers should be permitted to elect any term for their first post-restructuring contract as long as they are willing to pay the maximum rate. It reads Order No. 636-A to permit that result,

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190. Order No. 636-A at p. 30,637-39.

and to defer the application of the right of first refusal procedures until after the term of the first contract. UtiliCorp Division also ask a subsidiary question: If the existing capacity holders whose sales contracts expire on or before November 1, 1993, have to match the length of terms offered by competing bidders, do they have to offer to enter into contracts for a term of 15 years, as Williams requires, or may they simply agree to match the length of term offered by competing bidders?

The Commission will not address the specific facts and circumstances in the Williams restructuring proceeding in this generic order. However, UtiliCorp Divisions' rehearing request indicates a general area of confusion which needs clarification.

Questions have arisen about the applicable policies when long-term bundled sales contracts expire after the effective date of Order No. 636, but before the effective date of a pipeline's blanket sales certificate under section 284.284, when the pipeline's bundled sales service is converted to unbundled sales and transportation services. The pipeline must continue to provide service under the service obligation of its existing certificate until its section 284.284 blanket certificate becomes effective. The pipeline and the sales customer may enter into a relatively short-term contract, intended to apply until the effective date of the pipeline's blanket sales certificate under section 284.284. If the pipeline and the sales customer enter into a contract for bundled sales service that extends beyond the date that the pipeline implements unbundled service, the contract will be converted into an unbundled sales and unbundled transportation contract on the effective date of the pipeline's 284.284 blanket certificate. The question arises whether the sales customer whose contract lapses during the restructuring process, and which is not renewed, has a right of

first refusal to retain its firm transportation capacity upon the effective date of the pipeline's section 284.284 certificate, and whether a customer with a short-term interim sales contract has a right of first refusal to retain its capacity upon expiration of its short-term contract on or after the effective date of the pipeline's section 284.284 certificate.

In *ANR Pipeline Company*,[191] the Commission decided to treat short-term (less than one year) interim, bundled sales contracts as long-term contracts for purposes of affording the bundled sales customers the right of first refusal to avoid automatic abandonment of their firm transportation capacity — even if the contracts in fact expire in less than one year. The Commission will apply the same treatment given to short-term contracts in *ANR* to other pipelines undergoing restructuring whose long-term sales contracts expire during the restructuring process. A customer whose long-term bundled sales contract (one year or more) expires after May 18, 1992, but before the effective date of a pipeline's section 284.284 certificate, is entitled to retain its firm capacity by exercising a right of first refusal, as described in section 284.221(d) of the Commission's regulations, in connection with implementation of the pipeline's section 284.284 certificate. The customer is entitled to exercise its right of first refusal to avoid abandonment of service whether or not it executes an interim contract, or upon expiration of any interim contract, whether the interim contract is for more or less than one year.

In exercising this right of first refusal in connection with implementation of the pipeline's section 284.284 certificate, a customer is entitled to retain its firm capacity by matching the

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191. 60 FERC ¶ 61,319 (1992).

price offered by a competing bidder, up to the maximum rate,[192] and the duration of the term bid, up to a maximum of 20 years. The pipeline may not require a customer exercising its right of first refusal to contract for some term of longer duration than a term offered by a competing bidder. And, as the Commission said in Order No. 636, if there are no competing bidders, the existing customer is entitled to continue service for whatever term it chooses.[193]

3. Liability of Existing Shipper for Reallocated Capacity

Barclays seeks clarification that if capacity is reallocated during restructuring, and a new shipper's contract is for a shorter term than the existing shipper's term, the existing shipper will remain liable for the remainder of the term of the original contract. Barclays argues that if a holder of long-term firm capacity seeks to relinquish that capacity to another bidder during the restructuring proceeding, the pipeline, in addition to applying its creditworthiness standards, should remain protected not only from a shortfall in price but also from a shortfall in contract duration.

The Commission will grant this clarification. In Order No. 636-A, the Commission stated that when another creditworthy

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192. The pipeline may choose not to accept any bid at less than the maximum, in which event the existing customer will have to pay the maximum rate to retain its capacity. See Order No. 636-A at p. 30,629. However, as discussed above, if the pipeline refuses to accept a bid at less than the maximum rate, and the capacity goes unsubscribed, then this will be given significant weight in the pipeline's next rate case.

193. Order No. 636 at p. 30,449.

shipper offers to pay a rate that is equal to or greater than the existing capacity holder's rate for a *part* of the capacity the existing holder seeks to relinquish, a pipeline would be required to release the existing capacity holder from its contractual obligation for the part sought by the other shipper.[194] By extension, an existing capacity holder remains liable under the original contract for any part of a term remaining under the original contract when the contract of the shipper to whom capacity is relinquished expires.

4. Discounted Transportation Rates

CIG argues that the Commission erred in permitting an existing shipper with a contractually guaranteed transportation discount to retain the capacity in the restructuring proceeding by matching bids only up to the contractual rate, rather than the maximum rate. According to CIG, this policy undermines the allocative efficiency of capacity reallocation during restructuring. At the very least, CIG contends, an existing shipper with a discount that will not match higher bids for the capacity should not be entitled to the service enhancements provided for firm service under Order No. 636.

The allocative efficiency of capacity reallocation during restructuring is subordinate to the contractual rights of existing capacity holders. If a shipper contracted for long-term transportation capacity at a guaranteed discount, and has a contract that establishes its contractual right to receive that discount, the shipper is entitled to the benefits of its bargain under the contract, even if unforeseen circumstances render that service more valuable than it was when the bargain was made.

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194. Order No. 636-A at p. 30,639.

This result is merely the obverse of the continuing liability of a shipper that agreed to pay the maximum rate under its contract, even though unforeseen circumstances result in the shipper's rates unexpectedly increasing, or the shipper's need for the service unexpectedly decreasing.

5. Direct Feed Situations

UGI describes a contract for purchase of gas from Columbia under which delivery is made to UGI from Texas Eastern, a pipeline upstream of Columbia, a situation UGI characterizes as a "direct feed." UGI requests the Commission to clarify that if Columbia assigns its capacity on Texas Eastern to UGI, UGI will be entitled to a reduction in firm entitlements from Columbia, without exit fees or transition cost allocation, following the assignment of "direct feed" upstream capacity. Otherwise, UGI asserts that it will be liable for demand charges and transition cost charges to both Texas Eastern and Columbia for the same firm capacity.

The Commission will not attempt to resolve this case-specific issue arising from what appears to be an anomalous situation in this generic proceeding. The issue should be presented in Columbia's restructuring proceeding.

B. Transition Costs

1. Allocation of Gas Supply Realignment Costs to Interruptible Transportation

In Order 636-A, the Commission required pipelines to recover 10 percent of their gas supply realignment (GSR) costs through their rates for interruptible transportation (IT) under

their Part 284 blanket certificates. Many of the requests for rehearing of Order No. 636-A take issue with this requirement. Various parties oppose the allocation of GSR costs to interruptible transportation customers and propose that such costs be recovered from firm transportation (FT) released under the pipeline's capacity release program, or released firm transportation subject to a right of recall, as well as interruptible transportation. Some parties advocate that the 10 percent of GSR costs allocable to interruptible transportation should be recoverable from firm transportation if the pipeline does not provide interruptible transportation service, or if the volumes of interruptible transportation service it provides are insufficient to bear the 10 percent allocation. Other parties propose that a higher percentage of GSR costs should be recoverable from interruptible transportation service, or that all GSR costs should be recoverable through a volumetric surcharge on all throughput.

a. Arguments against the allocation to IT

The American Paper Institute asserts that GSR costs should not be allocated to interruptible transportation customers, or at least, not to the extent that interruptible transportation customers pay higher GSR costs per unit than firm transportation customers. GSR costs should not be allocated to Part 284 interruptible transportation customers, the Paper Institute argues, because interruptible transportation customers will not benefit from Order No. 636, they have not and will not cause GSR costs, and achieving the transition required by Order No. 636 through subsidization by interruptible customers is not in the public interest. It is not appropriate, according to the Paper Institute, to view opportunities for interruptible transportation customers to obtain firm service through the capacity release program as a basis for charging GSR costs to interruptible

transportation customers. Furthermore, the unbundling requirements of Order No. 636 do not benefit interruptible transportation customers, and pipelines in many restructuring proceedings are attempting to reduce the scheduling and balancing flexibility available to traditional transportation services, including interruptible transportation service.

The Paper Institute also notes that if the amount of interruptible transportation throughput is sufficiently low, it is conceivable that interruptible transportation customers could pay more, on a per unit basis, than do firm customers, and advocates that the Commission should at least adopt a mechanism which avoids that result.

Industrial Groups argue that the Commission's decision to allocate 10 percent of the GSR costs to interruptible transportation services is arbitrary and capricious, and that the rate impact of spreading GSR costs to a shrinking class of interruptible transportation customers is significant, and far out of proportion to any imaginable benefit to interruptible transportation shippers from the restructuring rule.[195] Industrial Groups argue that the Commission erred in Order No. 636-A by allocating GSR costs to interruptible transportation and non-converting firm transportation customers without a showing that interruptible transportation and non-converting firm shippers have contributed in any way to the incurrence of such costs, or that the ordered level of allocation produces just and reasonable

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195. They argue that the Texas Eastern filing of nearly $.28 per dekatherm for the GSR charges on interruptible transportation, which more than doubles the cost of various production and market area hauls, illustrates that the Commission cannot arbitrarily assign a predetermined percentage of costs to interruptible transportation.

rates. They also assert that sales contracts, and any costs that might be incurred to modify them, are unrelated to any service provided by pipelines for transportation customers who have never been pipeline sales customers, or who converted to transportation before the issuance of Order No. 636.[196]

Industrial Groups assert that interruptible transportation customers are provided no additional rights or services under the restructuring rule, and that because GSR costs are sales-related, they are not affected by the amount of interruptible transportation service a pipeline provides. They argue that the initiatives adopted in Order No. 636, such as unbundling, flexible receipt and delivery points, and creation of a uniform national capacity release program, will enhance the ability of firm shippers to use their reserved capacity more efficiently, but diminish the quality and reliability of interruptible transportation service by reducing the amount of pipeline capacity available for interruptible transportation service. In fact, they argue, these measures may lead to complete displacement of interruptible transportation service. Industrial Groups also argue that the Commission's cost-spreading rationale is inconsistent with its decision to exempt NGA section 7 shippers

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196. Gas Consumers also argue that customers who pursued the Commission's policies under Order No. 436 and converted to transportation-only will not benefit from Order Nos. 636 and 636-A, and should therefore not bear the transition costs of restructuring, because they have already paid the transition costs of converting to transportation under Order No. 436. The rationale for allocating transition costs to firm transportation customers receiving service under Part 284 certificates, regardless of whether they are discontinuing purchases of gas from the pipeline, has been fully explained in Order No. 636-A, and will not be repeated in this order. *See* Order No. 636-A at p. 30,650.

and pipelines themselves from sharing transition costs.[197]

In the Commission's judgment, applying the principle of cost causation is more important when allocating costs and designing rates for the long term, and deviations from that principle may be justified for short term rates. The issue the Commission faces in this proceeding is how to provide for an equitable means of allowing recovery of the costs of the transition to a restructured pipeline industry and a more competitive natural gas market. The Commission recognizes that interruptible transportation service *as such* did not give rise to the GSR costs at issue here. Furthermore, interruptible transportation *as such* may not be enhanced or improved by the requirements of restructuring. However, customers that have historically used interruptible transportation, and may continue to use it on a restructured pipeline, have access to the enhanced firm services. More importantly, they will benefit significantly from access to the more competitive gas market that will be available as a result of restructuring. The Commission intends to spread the costs of transition over a broad base of customers that have access to these benefits.[198] Shippers on a restructured pipeline should not be able to completely avoid a fair share of the GSR transition costs by limiting their usage of the services available under the pipeline's Part 284 blanket certificate to interruptible transportation service.

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197. Arcadian also contends that there is no justification for treating IT shippers differently than section 7(c) shippers.

198. For the same reason, the Commission will deny LILCO's request that future open-access, transportation customers, that obtain service after restructuring is completed, should not be subject to transition costs.

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Producer Associations contend that the Commission erred by requiring that 10 percent of the GSR costs must be recovered through a usage surcharge on interruptible transportation because of the adverse effect of such charges on the net-back price of gas at the wellhead. Blue Flame also alleges that recovery of 10 percent of the GSR costs from interruptible transportation penalizes small and medium sized producers because of the net-back effect on spot prices.

Arkla states that the Commission apparently recognized cost causation principles in deciding not to allocate GSR costs to individually certificated section 7(c) transportation agreements, but failed to consider these principles in allocating GSR costs to Part 284 interruptible transportation customers.

The Commission recognizes that allocation of a small portion of a pipeline's GSR costs to interruptible transportation service may have some adverse impact on producer prices, at least for some transactions for a short term, but the public interest in a more equitable spreading of such costs to a broad base of pipelines' customers outweighs the possible short-term impacts on producers. The restructuring requirements of Order No. 636 are applicable to service under a pipeline's Part 284 blanket certificate. They do not pertain to transportation service under individual section 7(c) certificates. Part 157 shippers therefore do not get either the benefits or the burdens of Order No. 636.

b. Recovery of GSR costs not recoverable from IT

Several petitioners contend that the Commission should permit alternative mechanisms for recovery of the 10 percent of

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GSR costs allocated to interruptible transportation, such as applying an equivalent surcharge to released firm capacity, either capacity subject to recall or all released capacity.[199] These petitioners assert that, with the implementation of capacity release, they will be unable to recover the GSR costs assigned to interruptible transportation, because competition from released capacity will significantly reduce interruptible throughput, and the imposition of a surcharge on interruptible transportation will further reduce interruptible sales by making the rates for interruptible service uncompetitive with the rates for released capacity. They maintain that released capacity is the equivalent of interruptible capacity and should therefore bear the same responsibility for GSR costs.

The Commission does not agree that the implementation of capacity release programs will necessarily result in the elimination of interruptible transportation service or in the pipeline's inability to recover GSR costs assigned to such service. Nor will the allocation of GSR costs necessarily make interruptible transportation uncompetitive with released firm capacity or reduce interruptible throughput. If the market for interruptible transportation is competitive, as petitioners assume, pipelines will price to reflect competitive forces in the market, not costs. By pricing interruptible transportation competitively, the pipelines should be able to continue to sell the service. The Commission is not requiring pipelines to allocate such a high level of GSR costs to interruptible transportation service so that rates which recover such costs will render the service unmarketable.

Natural requests clarification that the Commission will allow

199. ANR (recallable releases); CIG (recallable releases); Southern (all releases); Tenneco (all releases).

the pipelines to develop mechanisms to adequately deal with any underrecovery of costs allocated to interruptible transportation. Natural asserts that the allocation of transition costs to interruptible transportation service will undermine the Commission's principle of 100 percent recovery of transition costs unless the Commission clarifies that pipelines are to be afforded flexibility to develop adequate mechanisms to deal with any underrecovery. According to Natural, higher rates for interruptible transportation service will render increasingly difficult the collection of any of the costs required by Order No. 636-A to be allocated to such service. Natural urges the Commission to permit a wide range of alternative mechanisms for recovery of the GSR costs allocated to interruptible transportation under Order No. 636-A, including

* allocation of zero non-gas fixed costs to interruptible services, with actual dollars collected by the pipeline for these services used first to collect the transition costs;

* direct billing (and/or reallocation to the demand surcharge or other cost recovery mechanism) of any underrecovered amounts after a predetermined time period;

* recovery in a later period (and/or under a different mechanism) of costs not recovered earlier due to seasonal or market factors.

K N asserts that because interruptible transportation is not available on all pipelines, and, where it is available, actual throughput may be significantly less than projected throughput used to design rates, the requirement that GSR costs be recovered from interruptible transportation customers may mean that

certain pipelines will not recover 100 percent of their gas supply realignment costs, absent an unconditional true-up mechanism applicable to all *firm* Part 284 transportation customers, which provides for recovery of carrying charges. LILCO, on the other hand, seeks clarification that a true-up mechanism for recovery of GSR costs allocated to interruptible transportation service may *not* provide for recovery from firm transportation service, but only from future interruptible service.

POPCO and PIOC allege that the Commission cannot require 10 percent of their GSR costs to be recovered from interruptible transportation service because they have never provided, and never expect to provide, interruptible transportation service. According to POPCO and PIOC, they were both certificated as gas supply projects, not transportation networks, and both are "open access" transporters pursuant to Order No. 509, but neither have ever received a request for firm or interruptible transportation of a presently deliverable gas supply. POPCO states that if the Commission applies its "90-10" rule to POPCO and PIOC, both pipelines will be denied an opportunity to recover the 10 percent of GSR costs allocated to interruptible transportation service.

The effect of capacity releasing on the levels and rates for interruptible transportation, and the ability to recover the assigned GSR costs, will depend on many factors, including the extent of projected GSR costs, characteristics of the pipeline's system, the pipeline's capacity release procedures, the extent to which flexible receipt and delivery points are available, the rate design used for interruptible transportation, and the use of seasonal contract entitlements.[200] As the Commission stated in

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200. For example, as the Commission pointed out in Order No. 636-
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Order No. 636-A, the Commission does not intend for the pipelines to have to absorb the portion of GSR costs assigned to interruptible transportation and encourages the pipelines and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover those costs.[201] Furthermore, if a pipeline's experience after restructuring indicates that it will be unable to recover the 10 percent of GSR costs allocable to interruptible transportation, either because it is providing no interruptible transportation, or a *de minimis* level of such transportation, the Commission will consider proposals in limited section 4 rate filings to provide for recovery of those unrecoverablecosts.[202] However, the Commission will not accept proposals to assess any of the 10 percent of GSR costs allocable to interruptible transportation solely to *released* firm capacity. Released firm capacity already bears the cost of the reservation fee surcharge. Thus, permitting pipelines to assess the use of released firm capacity with an additional increment of GSR costs, while the pipeline's

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A, under a potential revenue crediting approach for interruptible transportation, pipelines could retain a portion of the revenue from interruptible transportation to recover GSR costs allocated to interruptible transportation. Order No. 636-A at p. 30,563 n. 164. The use of seasonal contract entitlements likely would result in interruptible transportation being available in the off-peak season.

201. Order No. 636-A at p.30,647.

202. This order constitutes such appropriate notice under the Natural Gas Act as may be necessary to the public, including all current and future shippers, that the Commission expects to take appropriate steps in the future to ensure that the pipelines have an opportunity to recover any unrecoverable GSR costs allocated to IT service.

interruptible transportation bears only one such assessment, would give an undue competitive advantage to the marketing of interruptible transportation.

c. Recovering a higher percentage of GSR costs from IT, or all GSR costs through a surcharge on all throughput

Gas Consumers advocate the reduction or elimination of transition costs to firm transportation customers, particularly small customers, and reallocation to producers and interruptible customers, the primary beneficiaries of the restructuring. Gas Consumers argue that a portion of *all* transition costs, not just GSR costs, should be allocated to interruptible transportation customers, and that the allocation should be based on the benefit received by allocating transition costs on the basis of throughput or some other method that assigns costs based on benefits rather than an arbitrary percentage.

New Jersey Natural contends that the Commission erred by failing to allocate 50 percent of the GSR costs to interruptible transportation service, commensurate with the benefits interruptible customers have received from pipeline restructuring.

Peoples Gas argues that transition costs should be allocated to interruptible transportation (as well as all other) customers volumetrically on a *pro rata* basis to reflect more accurately their use of pipeline services and the improved quality of service that the Commission intends for all customers to receive in the future. The Commission's decision to require the allocation of only 10 percent of the GSR costs is improper and unreasonable, according to Peoples Gas, because end-use customers getting their gas delivered through interruptible transportation were

probably all sales customers of pipelines or LDCs when the pipeline contracts giving rise to the GSR costs were entered into, and interruptible transportation customers are presently a major customer group on the pipeline systems, and the most likely beneficiaries of the restructuring rules.

Western Resources argues that allocation of GSR costs should have been left to individual proceedings. According to Western Resources, recovery of 10 percent of the GSR costs from interruptible transportation service is not enough on Williams' pipeline system, and the Commission erred by so limiting the recovery of such costs.

The task of determining fair allocations of transition costs is ultimately thankless, even though we bring all our experience and best judgment to bear on it. The Commission has already considered and rejected the arguments against *any* allocation of GSR costs to interruptible transportation service. The Commission will also reject the requests to require the allocation of *more* GSR costs to interruptible transportation service and to allocate such costs on a volumetric basis. As the Commission explained in Order No. 636-A, assessing 10 percent of the transition costs to interruptible rates will be a short term feature of the pipeline's rates and is a reasonable trade-off in light of the rule's long term benefits.[203] Thus, a 10 percent allocation of GSR costs to interruptible transportation customers is a reasonable accommodation of the many factors and interests at issue here.[204] As the United States Supreme Court has stated,

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203. Order No. 636-A at p. 30,647.

204. *See* Christian Broadcasting Network, Inc. v. Copyright Royalty Tribunal, 720 F.2d 1295, 1304 (D.C. Cir. 1983)(choice of a particular percentage allocation not reviewable for exact precision, but simply for rationality).

"[a]llocation of costs is not a matter of the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[205]

The provisions of Order Nos. 636 and 636-A on allocation of transition costs are not incorporated in the regulations, but are policy statements. The Commission will review specific proposals for recovering transition costs with reference to the particular circumstances of each pipeline system and the degree of support those proposals enjoy from the affected parties.

d. Use of a surcharge vs. allocating GSR costs to interruptible transportation

LILCO states that the Commission erred by requiring pipelines to *allocate* 10 percent of their GSR costs to interruptible transportation service instead of recovering such costs through a *surcharge* on interruptible transportation. According to LILCO, pipelines will simply reduce the costs that they would otherwise allocate to interruptible service by an amount sufficient to offset the allocated GSR costs, so that interruptible customers will not in fact pay any GSR costs, and rates to firm transportation shippers will not be any lower. Furthermore, LILCO asserts, if pipelines adopt a crediting method of accounting for interruptible transportation revenues, firm transportation customers will be deprived of any credit for the GSR costs allocated to interruptible service, and will thus be paying those costs indirectly.

The Commission will deny LILCO's request for rehearing. Ten percent of a pipeline's GSR costs must be *allocated* to the

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205. Colorado Interstate Co. v. FPC, 324 U.S. 581, 589 (1945).

rates for its interruptible service, and may not be recovered through a surcharge. Although LILCO makes the valid point that the allocation of GSR costs to a service with rates determined by competitive forces may not necessarily affect the rates they charge, the allocation of GSR costs increases the maximum rates for interruptible transportation, and service provided at the maximum rates will recover more costs than service at maximum rates without the allocation. Whether GSR costs are directly allocated to interruptible transportation service or recovered by means of a volumetric surcharge on interruptible rates would not alter the effect of competition on discounted transportation rates. The Commission will consider the fairness of a pipeline's proposed allocation of costs to interruptible and firm service, or the fairness of any proposed mechanism for crediting revenue from interruptible service to firm transportation customers, on a case-by-case basis.

e. True-up mechanisms to ensure recovery of GSR costs allocated to interruptible transportation service

Arcadian states that the Commission erred in authorizing true-up mechanisms to recover gas supply realignment costs allocated to interruptible transportation service. Arcadian argues that a true-up mechanism, which would assure a pipeline that any GSR costs not recovered through interruptible transportation rates in one period would be recovered in subsequent periods, would create the same problems as revenue crediting, by eliminating incentives for a pipeline to market interruptible services, and conflict with the Commission's primary aim of improving the competitive structure of the natural gas industry.

Appendix D

As noted above, in Order No. 636-A, the Commission stated that it does not intend for the pipelines to absorb any portion of the GSR costs and encouraged the pipelines and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover those costs.[206] Putting a pipeline "at risk" of not recovering those costs by requiring it to assign a certain amount of GSR costs to the rate for each unit, on the basis of an estimated level of interruptible transportation volumes, might increase the pipeline's incentive to provide interruptible transportation at the estimated level. However, such a policy would not necessarily improve the pipeline's ability to market the estimated level of interruptible service or provide a reasonable opportunity to recover the assigned GSR costs.

2. Recovery of Costs in Account No. 191 Accrued Before July 31, 1991

INGAA advocates allowing direct billing through the PGA mechanism of pre-July 31, 1991 costs in pipelines' Accounts No. 191. According to INGAA, the Commission's analysis of the issue in Order No. 636-A overlooked the fact that there are still unrecovered gas costs which accrued prior to July 31, 1991, that will be outstanding upon compliance with Order No. 636 and termination of the PGA mechanism. INGAA asserts that pipelines with such costs may not have an ample opportunity to recover them in the last remaining PGA periods, because pre-July 31, 1991 underrecoveries would not normally be recovered until the 1993 PGA year. INGAA asserts that the Commission needs to specifically provide a mechanism for

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206. Order No. 636-A at p.30,647.

recovery of these prudently incurred costs which would have, until the issuance of Order Nos. 636 and 636-A, been fully recoverable under the PGA rules. INGAA also states that the Commission should provide for a waiver of the PGA regulations and allow the pipeline to include all such costs in its demand charge during the final PGA period.

CNG states that the Commission's conclusion that pipelines will have an ample opportunity to recover their pre-July 31, 1991 costs before they terminate their PGA mechanisms is wrong. CNG asserts that the Commission has twice rejected CNG's requests to obtain demand charge treatment for the recovery of Texas Eastern's GSIRC charges, and has instead required CNG to recover those amounts in its commodity surcharge. CNG asserts that, as a result, it has accumulated significant amounts in its Account No. 191 that would be difficult to recover under the normal operation of the PGA mechanism.[207]

Columbia requests clarification that Order No. 636-A does not preclude recovery of pre-July 31, 1991 gas costs if a pipeline can show that there are valid reasons why such costs have not been recovered via the PGA mechanism. Columbia states that it has not, as yet, made certain payments to its gas suppliers relating to its gas purchases during periods preceding its bankruptcy filing and cannot do so absent an appropriate order of the Bankruptcy Court. Columbia predicts that such an order will not be issued in time for such costs to be recovered prior to the elimination of its PGA.

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207. *See* CNG Transmission Corporation, 61 FERC ¶ 61,156 (1992)(Commission accepted tariffs, subject to refund and further review, to accelerate recovery of CNG's Account No. 191 balances and thereby minimize transition costs upon restructuring.)

Appendix D

Natural urges the Commission to acknowledge that particular situations may arise which require a case-by-case examination of the PGA recovery issue. Natural states that its PGA was suspended as of December 1, 1990, under its Gas Inventory Demand Charge (GIDC) procedures, and that while certain amounts collected pursuant to the GIDC have been applied to recovery of the PGA balance, Natural expects that, absent a further settlement, some balance will remain as of the date Order Nos. 636 and 636-A are fully implemented on its system.[208]

PSE&G requests clarification that any pre-July 31, 1991 costs in Account No. 191 not recovered before termination of a pipeline's PGA must be absorbed by the pipeline.

UtiliCorp Divisions request the Commission to grant rehearing on its treatment of Account No. 191 balances, which UtiliCorp Divisions characterize as in essence an adoption of a FIFO (first-in, first-out) method for determining whether accumulated balances have been eliminated. According to UtiliCorp Divisions, Commission statements in Order No. 636-A imply that a pipeline may attribute *all* of its recovery of gas costs under its PGA mechanism to reduction of its unrecovered balanced accrued before July 31, 1991 — even during periods when unrecovered balances are increased — and argues that such an accounting method would permit pipelines to circumvent the filed rate doctrine.

The Commission recognizes that, due to various specific

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208. *See* Natural Gas Pipeline Company of America, 61 FERC ¶ 61,238 (1992) (order approving settlement on, *inter alia*, past PGA balances and underrecoveries of GIDC costs).

circumstances, such as those described above, some pipelines will not be able to recover all of their unrecovered purchased gas costs that had accrued before July 31, 1991, under the normal application of the regulations, before they terminate their PGA mechanisms upon implementation of restructuring. Therefore the Commission will give serious consideration to petitions for waiver of provisions of the regulations, *e.g.*, the provisions regarding the FIFO method, if necessary to afford pipelines a reasonable opportunity to recover their pre-July 31, 1991 costs before the termination of their PGA mechanisms. Although the Commission will be flexible in the application of the PGA regulations in order to enable the pipelines to recover the costs in Account No. 191, the Commission cannot permit radical departures from the principles upon which the PGA regulations are based.[209]

Waivers of the technical provisions of the PGA regulations may not be sufficient, however, to afford some pipelines a reasonable opportunity to recover all of their pre-July 31 costs, and some pipelines may be unable to recover those costs prior to termination of their PGAs. The Commission will consider creative proposals developed by pipelines to enable them to recover their costs[210] that do not run afoul of the filed rate doctrine.

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209. *See, e.g.*, Carnegie Natural Gas Company, 60 FERC ¶ 61,225 (1992) (Commission denied Carnegie's request for waiver of the regulations to suspend its surcharge rates and to offset its commodity surcharge balance with demand refunds); and CNG Transmission Corporation, 60 FERC ¶ 61,227 (1992) (Commission denied a request for a waiver of the regulations to defer recovery of a portion of surcharge balance and to use refunds to offset that balance).

210. *See, e.g.*, CNG Transmission Corp., 61 FERC ¶ 61,156 (1992) (permitting sale of gas from storage inventory).

The Commission also encourages the pipelines and their customers to enter into settlements to resolve the recovery of any remaining Account No. 191 balances. Accordingly, the Commission will clarify and expand its prior policy to allow proposals from pipelines for special billing mechanisms to recover such costs, and will consider the merits of their proposals on a case-by-case basis. These proposals should be filed as part of the pipeline's restructuring compliance filing. By inviting these proposals, however, the Commission has no intent to be so flexible as to permit a delay in the implementation of the unbundling requirement.

3. Eligibility of Costs for 100 Percent Recovery as GSR Costs

a. Eligibility to recover GSR costs incurred outside restructuring

CNG argues that the Commission should grant clarification to permit pipelines to recover as transition costs those GSR costs, whenever incurred, that are reasonably related to the pipeline's implementation of Order No. 636. CNG wants the Commission to authorize pipelines to engage in the process of reforming their contracts immediately, even before their customers make final decisions concerning their sales entitlements. Furthermore, CNG does not want the Commission to impose deadlines on the recovery of GSR costs. CNG argues that if a producer-supplier knows that the pipeline will be unable to recover its GSR costs unless a settlement is reached by a certain date, the producer-supplier will be unwilling to negotiate.

INGAA objects to the Commission's statement in Order No. 636-A that the use of a surcharge on transportation rates to

recover GSR costs will be limited to such costs that arise as a result of customers' decisions as a result of the restructuring proceedings, and that if customers reduce or terminate their sales entitlements upon expiration of their contract terms after restructuring, the costs of any further gas supply realignments would only be recoverable through market-based sales rates.[211] INGAA requests the Commission to clarify that the mechanism to recover gas supply realignment costs will be applicable to all prudently incurred costs resulting from pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers, even if these costs arise outside of the formal restructuring period.

Tenneco requests the Commission to clarify that pipelines may realign contracts prior to implementation of their restructured services. Tenneco notes the Commission's statement in Order No. 636-A that "[i]f all customers terminate their sales entitlements during restructuring, a pipeline may have to buy out all of its gas supply contracts. . . ,"[212] and seeks clarification that this statement does not, by implication, prohibit pipelines from realigning contracts *prior to* implementation of their restructured services. Tenneco asserts that early contract realignment will help to reduce transition costs.

K N seeks clarification that sales customers whose contracts expire after restructuring remain liable for GSR costs. K N states that it does not believe that current sales customers whose contracts will expire in the near future are allowed under Order Nos. 636 and 636-A to escape gas supply realignment costs by

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211. Order No. 636-A at p. 30,649.

212. *Id.* at p. 30,657.

requiring that K N remain in the merchant role only for the duration of their current contract, and then escaping without any gas supply costs responsibility.

The Commission denies rehearing of the eligibility issues raised in the rehearing petitions. As the Commission explained in Order Nos. 636 and 636-A, a pipeline's costs of realigning gas supply contracts are eligible for recovery if these costs are attributable to the implementation of Order No. 636.[213] The costs eligible for recovery are limited to costs that arise as a result of sales customers' decisions during the restructuring proceedings either to reduce or terminate their gas supply obligations with the pipeline.[214] In their compliance filings, pipelines must propose a mechanism for recovery of these costs.

The determination of whether specific costs are attributable to the implementation of Order No. 636 will have to be decided on the basis of the specific facts. Pipelines do not have to delay entering into negotiations to realign their gas supply contracts until after their customers have made final choices during the course of the restructuring proceedings in order for the costs of those realignments to be eligible for the special billing mechanisms for GSR costs under Order No. 636.[215] However, a pipeline may not retain contracts to provide gas

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213. Order No. 636 at p. 30,459.

214. Order No. 636-A at p. 30,649.

215. Enron requests clarification that the definition of GSR costs includes costs resulting from pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers. The Commission grants this request. Both such costs are included.

sales in a competitive market and then seek recovery for any further realignment of those contracts that may become necessary. As the Commission stated in Order No. 636-A, pipelines continuing to engage in a merchant function after restructuring are free to set the prices and terms for those contracts, but, by the same token, must bear the risk of their decisions and provide for further realignment in their gas supply agreements.[216]

Enron asserts error in the Commission's statement that Order No. 636 was not intended to affect the provisions of existing settlements resolving transition costs. Specifically, Enron cites the Commission's decision in *Florida Gas Transmission Company*[217] that the costs of certain take-or-pay settlements entered into in December 1991 and January 1992, and subject to the provisions of Florida Gas' transition cost recovery (TCR) mechanism, could not be eligible for recovery as GSR costs under Order No. 636. Enron argues that the Commission improperly established a "bright line" test for eligibility, without giving Florida Gas an opportunity to show that the issuance of the NOPR in this proceeding had significantly altered the circumstances under which Florida Gas had agreed to its TCR mechanism, and had caused the incurrence of the gas supply realignment costs in question.

The Commission will not address case-specific applications of its rule in this generic proceeding, but will address these issues in specific cases. The Commission has already rejected Florida Gas' arguments on rehearing for allowing it further

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216. Order No. 636-A at p. 30,649.

217. 59 FERC ¶ 61,413 (1992).

opportunity to establish the eligibility for recovery of the costs in question as Order No. 636 transition costs.[218]

CIG asks for clarification that the GSR cost recovery mechanism can be utilized in connection with the realignment of producer contracts that extend beyond the term of existing sales contracts. The Commission grants the requested clarification. Prior to Order No. 636, pipelines' service obligations to their sales customers extended beyond the expiration of their sales contracts with those customers. Thus, the fact that the terms of gas supply contracts to be realigned extend beyond the terms of an existing pipeline's sales contracts has no bearing on the eligibility for recovery of the costs of realigning those contracts as transition costs under Order No. 636.

b. Eligibility for recovery of GSR costs by pipelines with GIC mechanisms

Enron seeks clarification that a pipeline is not precluded from seeking to recover GSR costs where a pipeline has utilized a GIC mechanism. It seeks assurance that the Commission will consider, on a case by case basis, the ability of the pipeline to recover GSR costs through the Order No. 636 mechanism. ANR requests clarification that it will be permitted to recover its GSR costs through an Order No. 636 recovery mechanism

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218. *Id.*, 61 FERC ¶ 61,016 (1992). The Commission also will not address, in this proceeding, UGI's arguments on rehearing that the Commission should not allow Columbia to retain the benefits from the "Global Settlement" and prior agreements while freeing them from the risk assumed relating to contract management, and UGI's request for a ruling that Columbia may not recover contract rejection costs arising from its bankruptcy.

notwithstanding its implementation of a GIC charge for an interim period under a recently approved rate case and restructuring settlement.

The Commission reiterates that gas supply costs for which GIC charges have been collected cannot be recovered again as transition costs.[219] However, a pipeline may incur GSR costs as a result of its customers' actions under Order No. 636 that could not have been anticipated in designing the GIC and cannot be recovered through a GIC. The Commission will consider, on a case-by-case basis, whether the gas supply realignment costs attributable to an Order No. 636 restructuring of a pipeline with a GIC are eligible for recovery through the special billing mechanism of Order No. 636.

PGT requests clarification that a pipeline that establishes cost-based rates for its unbundled sales service will continue to be eligible for recovery of prudently incurred gas supply realignment costs under Order No. 636 or Order No. 528.[220] Initially, the basis of a pipeline's rates for its unbundled sales of gas is not relevant to its eligibility to recover take-or-pay costs under Order No. 528 or gas supply realignment costs under Order No. 636. As noted earlier, the basis for establishing the price for unbundled gas sales is a matter between the pipeline and its customers. The recovery of gas supply costs, including any costs of contract reformation after restructuring, must be

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219. Order No. 636-A at p. 30,654. The Commission prohibits a pipeline with a GIC mechanism in place from filing under Order No. 528 to recover take-or-pay costs.

220. The term "gas supply realignment costs" is applicable to transition costs incurred as a result of restructuring under Order No. 636, but not to take-or-pay buyout or buydown costs recoverable under Order No. 528.

negotiated by the parties. How the price under a particular unbundled sales contract is based will be a contractual, not a regulatory matter.

c. Prudence

Northern Indiana questions the Commission's statement in Order No. 636-A that downstream pipelines should not have to absorb any of the transition costs billed to them by upstream pipelines, and advocates holding downstream pipelines to the same standards of prudence review of transition costs as any other costs. The Commission is not requiring any pipelines — upstream or downstream — to absorb transition costs under Order No. 636. However, just as upstream pipelines are subject to challenges to their prudence with regard to incurring transition costs, the Commission clarifies that downstream pipelines will also be subject to such challenges in connection with passing through transition costs billed to them by upstream pipelines. The transition costs incurred by the downstream pipelines as a result of implementing this rule are like any other costs incurred by the pipelines, and nothing in this order is intended to preclude a challenge to their prudence.

CNG questions the Commission's statement in Order No. 636-A that the added presumption of prudence afforded to costs filed for recovery under Order Nos. 500 and 528 does not apply to GSR costs, and seeks clarification that the incurrence of GSR costs is presumptively prudent. CNG urges the Commission to reaffirm the established policy that a pipeline does not bear the burden of proving its prudence unless another participant introduces evidence that creates a serious doubt about the pipeline's prudence. The Commission clarifies that it has not changed the established burden of proof. The Order Nos. 500

and 528 special presumption of prudence, based on a percentage absorption of costs, does not apply to GSR costs.

Gas Consumers assert that prudence reviews do not sufficiently protect small customers. They also assert that if pipelines attempt to recover non-restructuring costs as transition costs, the practical burden is on the customers to prove the imprudence of those costs not associated with Order No. 636. Gas Consumers argue that the Commission should shift the initial burden of going forward on prudence to the filing pipeline and provide better guidance on what constitutes recoverable GSR costs under restructuring.[221]

The Commission will continue to develop policies and guidelines on defining what costs are eligible for treatment as GSR costs as issues arise. Pipelines have the burden of establishing that such costs are eligible for the special billing mechanisms under Order No. 636. As stated above, the special presumption of prudence under Order Nos. 500 and 528 do not apply, but customers will have the burden of presenting evidence that costs that would otherwise be eligible for such billing mechanisms cannot be recovered because they were not prudently incurred.

Cincinnati Gas argues that the Commission's decision to preclude prudence challenges to previously approved cost-recovering mechanisms under Order Nos. 500 and 528 cannot be fairly applied in the circumstances on the Columbia system. Cincinnati Gas requests the Commission to clarify that Columbia's customers and the affected state commissions will

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221. CNG also requests guidance as to identification of the kinds of costs that constitute GSR costs.

be permitted to challenge the prudence of the company's pre-Order No. 636 reformation costs in any proceeding involving the flowthrough of GSR costs. Cincinnati Gas also argues that the Commission should allow challenges to Columbia's prudence under the global settlement if its GIC is terminated. The Columbia-specific issues will be resolved in the appropriate proceeding concerning Columbia's GSR costs on the basis of the unique facts in that proceeding.

CNG states that the Commission should not presume that a pipeline's failure to exercise a "FERC-out" clause would be imprudent. CNG contends that the Commission should also assist pipelines by providing guidance on the propriety of exercising rights under a "FERC-out" clause. Specifically, CNG asks if any aspect of Order No. 636 has the effect of preventing a pipeline from recovering, as part of the pipeline's cost of service, the full amounts paid for natural gas, asserting that many of its gas purchase contracts contain a provision like this. Or do the provisions in Order No. 636 that permit pipelines to recover GSR costs mean that pipelines cannot rely on such contract language to excuse payment of the full contract price? CNG asserts that, without Commission guidance on this issue, litigation will arise in a host of jurisdictions and produce inconsistent interpretations of the Commission's intentions.[222]

The Commission did not establish any presumption of imprudence by a pipeline that fails to exercise a "FERC-out" clause. Nor will the Commission resolve questions about a pipeline's rights under particular provisions in a gas supply contract. First, the Commission's jurisdiction over producer

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222. CNG also raises this same question in a petition for declaratory order filed on October 16, 1992, in Docket No. RP93-12-000.

supply contracts is limited to only a very few contracts, and will be completely abolished as of January 1, 1993, under the provisions of the Natural Gas Wellhead Decontrol Act of 1989.[223] Furthermore, even if the Commission had jurisdiction over certain contracts in the days remaining before January 1, it would defer resolution of contract interpretation questions of the kind raised by CNG to state or federal courts. Under *Pennzoil Co. v. FERC*,[224] the Commission would be required to apply the applicable substantive state law to interpretation of such contracts, so an effort at Commission interpretation would not necessarily achieve the uniformity that CNG advocates.[225]

UtiliCorp Divisions objects to the Commission's statement in Order No. 636-A that it does not intend downstream pipelines to absorb any of the transition costs billed to them by upstream pipelines and the Commission's allowance of mechanisms in downstream pipelines' restructuring compliance filings to flow through those costs. UtiliCorp Divisions argues that such a policy violates the Commission's general policy against cost trackers and fails to provide an incentive for pipelines to vigorously contest both the prudence of the upstream pipeline in incurring such costs and the allocation of those costs to the downstream pipeline.

One-hundred percent recovery of Order No. 636 transition costs billed to downstream pipelines by upstream pipelines is consistent with the Commission's policy permitting such

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223. Pub. L. No. 101-60, 103 Stat. 157 (1989).

224. 645 F.2d 360 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

225. In view of this ruling on CNG's request for rehearing, its petition for declaratory order will also be denied for these reasons.

recovery of take-or-pay settlement costs under Order No. 528. Permitting the use of some form of tracking mechanism for such passthrough is reasonable in view of the nature of the costs, although the details of the recovery mechanism must permit reasonable opportunities for interested parties and the Commission to review and challenge the prudence of the costs.

4. Transportation Contracts at Fixed Rates or Discounts.

Enron objects to the Commission's statement in Order No. 636-A that "[i]f a pipeline agreed to provide transportation service at a fixed rate, without a right to passthrough any surcharges or other cost increases, then the pipeline will have to bear the costs of the bargain it made."[226] Enron contends that pipelines should be allowed to recover transition costs from customers with existing transportation service agreements containing fixed rates, discounts, or caps. Enron argues that pipelines could not have anticipated the transition brought about by Order No. 636 and the resulting transition costs, and that denial of relief from their fixed rate contracts is directly contrary to the assurances of Order No. 636 that pipelines could recover 100 percent of all prudently incurred transition costs.

Williston asserts that a pipeline may have entered into fixed rate transportation contracts with firm transportation customers that are not former sales customers, and may have been willing to accept the risk of underrecovery from these customers of a portion of the costs contemplated under Order Nos. 500 and 528, but that the sweeping restructuring mandated by Order No. 636 has fundamentally changed the assumptions on which

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226. Order No. 636-A at p. 30,662.

these agreements were based. Williston also objects to the Commission's rejection of the suggestion that pipelines be allowed to recover transition costs from other customers, or during later periods, when they are unable to fully recover such costs due to the need to discount transportation rates. According to Williston, the Commission's policy simply denies recovery of a portion of a pipeline's prudently incurred transition costs, despite general statements to the contrary.

Natural argues against the requirement of allocating GSR costs to transportation under fixed rates or discounted arrangements negotiated before issuance of Order No. 636-A. Natural states that it has had to offer discounts or enter into fixed rate contracts, and that allocation of transition costs to these contracts would, absent some alternative recovery mechanism, preclude Natural from recovering transition costs in direct contravention of the Commission's stated intent. According to Natural, it had no basis, at the time the agreements were negotiated, to anticipate that such arrangements would subject it to absorption of transition costs.

Natural also objects to requiring the allocation of transition costs to *future* discounted or fixed rate transportation agreements. Natural asserts that parties require a reasonable level of rate certainty to enter into firm transportation arrangements, and that since the transition costs a shipper may have to bear are not well defined, pipelines and shippers will be reluctant to enter into new contracts. Certain firm transportation arrangements will simply not bear the additional burden of transition costs, according to Natural, and the Commission's policy will distort the market for, and economics of, firm transportation.

The Commission clarifies that its statements in Order No.

636-A were not intended to apply a different standard to pipelines that offered discounts pre-restructuring. The Commission's policy is that pipelines will be permitted to recover 100 percent of their prudently incurred gas supply realignment costs that result from compliance with Order No. 636.[227] In their compliance filings, pipelines may propose methodologies to ensure their ability to recover their prudently incurred GSR costs given the individual circumstances on their systems, including discounted transportation provided pre-restructuring. Pipelines choosing to offer discounted firm transportation in the future, however, do so at the risk of not being permitted to recover GSR costs associated with those contracts.

5. Stranded Costs

CNG urges the Commission to provide guidance on the recoverability of stranded costs. Specifically, CNG wants to know whether the cost of facilities no longer needed to render restructured services — unused gathering facilities, production area stubs and laterals, non-productive assets, and any unrecovered purchased gas costs — are recoverable as stranded costs. CNG contends that after restructuring is complete and unbundled services begin, customers will challenge both the eligibility and prudence of the pipeline's transition costs. CNG states that few pipelines will be willing to risk the incurrence of costs that might arguably, for want of guidance, be challenged as ineligible stranded costs.

To be a "stranded cost," the item must no longer be "used or useful" after restructuring. To qualify for 100 percent recovery under Order No. 636, the facilities must have been rendered no

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227. Order No. 636 at p. 30,460.

longer used or useful as a result of the pipeline's compliance with the order. The Commission will consider issues concerning the eligibility for recovery of any claimed stranded costs in the proceedings where pipelines seek to recover such costs. However, once a pipeline's costs have been determined eligible for recovery as stranded costs, the pipeline may not subsequently seek recovery of those costs as an element of its cost of service in any future rate proceeding without recognition of the costs it has recovered as stranded costs.

Among the costs that are potentially eligible for recovery as stranded costs are the costs of capacity on upstream pipelines and upstream storage (Account No. 858 and 824), storage facilities, production facilities, products extraction facilities, gathering facilities, and transmission facilities. This list is not exhaustive and other costs will be considered on a case-by-case basis.

6. Miscellaneous

a. Exit Fees

CNG requests authorization to direct bill customers departing the system for their share of the GSR costs, if the customer refuses to agree to a negotiated exit fee. CNG argues that by declining to allow the unilateral imposition of an exit fee or a direct bill on departing customers, the Commission has substantially undercut the pipeline's ability to have the departing customer bear its fair share of the GSR costs. Furthermore, CNG argues that a departing customer's refusal to pay an exit fee will cause remaining customers to shoulder an increasing burden of the GSR costs. Williston also argues that the Commission's prohibition in Order No. 636-A of a unilateral imposition of

exit fees on a customer that is reducing or terminating sales, but is not reducing its reservation of transportation capacity, deprives pipelines of a legitimate vehicle for cost recovery.

The Commission clarified in Order No. 636-A that it was not authorizing the unilateral imposition of exit fees on customers that are reducing or terminating gas purchases from the pipeline, but not departing the system as transportation customers. As long as a customer remains on the system as a firm transportation customer of the pipeline, the pipeline can recover a portion of its GSR costs through the surcharge on that customer's transportation rates. Pipelines and their customers may negotiate exit fees in lieu of, or in combination with, a surcharge on reservation fees for recovering GSR costs. The Commission strongly encourages this.[228] A customer may also negotiate the payment of an exit fee for a release from its obligation to pay for firm transportation capacity, and thus depart the system altogether. But, absent such a negotiated exit fee, the Commission will not require customers to pay exit fees or permit them to be direct billed for the recovery of GSR costs.

b. Limited section 4 filings to recover transition costs

UtiliCorp Divisions also objects to the Commission's clarification in Order No. 636-A (which UtiliCorp Divisions contends is a change in position rather than a clarification) that pipelines may file to recover GSR costs and to direct bill

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228. If a customer leaves the system as a transportation customer *before* its contract expires, the pipeline will be in a posistion to charge that customer an exit fee since the early (and valid) termination of the contract can only be accomplished by mutual agreement by the pipeline and shipper.

Appendix D

Account No. 191 balances in limited section 4 proceedings. UtiliCorp Divisions argues that the Commission's actions here contrast, without reasoned basis, with its prior rulings barring transition cost trackers in the context of gas inventory costs charges by an upstream pipeline to a downstream pipeline. UtiliCorp Divisions contends that only if all costs are considered in one proceeding, both those which have increased and those which have decreased, can the Commission be assured that the overall rates charged customers are reasonable as required by the NGA.

Unrecovered Account No. 191 balances and GSR costs may be recovered through one-time-only or short-term charges that are not necessarily related to a pipeline's ongoing patterns of revenues and expenses. Accordingly, there is no particular benefit in reviewing the amounts or eligibility for recovery of these costs, along with all of the pipeline's other costs, in the context of a general section 4 rate case. Moreover, the details of the cost recovery mechanisms will have been resolved in the restructuring proceedings prior to the time limited section 4 filings are made to recover these costs.

Transco requests the Commission to allow limited section 4 filings to recover stranded costs. Transco states that the requirement to use a full-blown section 4 rate case to recover stranded costs is administratively burdensome, because it is predictable that every pipeline will incur stranded costs, and the Commission and interested parties will be inundated with a new major rate case by every restructuring pipeline. According to Transco, stranded costs do not represent new costs, but costs that are currently being collected in rates in a manner that can be expected to change as a result of restructuring, and the requirement of a full section 4 rate filing will deny pipelines

full recovery of transition costs by delaying the implementation of rates to recover costs no longer recovered under restructured rates. There is enough for affected parties to do in the next year, Transco asserts, without imposing the demands of a full-blown general rate proceeding, where a proceeding on a limited section 4 filing would afford a fair examination of the costs at issue.

The Commission will allow pipelines to make limited section 4 filings to recover Account No. 858 costs and the costs of stranded facilities that are currently incrementally priced, such as storage facilities on some pipeline systems. Since these costs are already in the cost of service, they could be recovered through a tracking-type procedure. However, pipelines must file to recover the costs of most, if not all other stranded facilities in general section 4 rate proceedings. A full section 4 proceeding is necessary because of the necessity of determining depreciable plant balances, associated taxes and other direct costs, and appropriate allocations of indirect costs to the stranded items.

c. When can pipelines begin recovery of transition costs?

PSE&G requests clarification that even a limited section 4 filing to recover transition costs must comply with the requirement of section 154.63(e)(2) of the Commission's regulations[229] that any projected estimate of such costs must be known and measurable with reasonable accuracy as of the date of the pipeline's filing.

PSE&G also requests clarification that a pipeline may not

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229. 18 CFR § 154.63(e)(2)(1992).

begin to recover any transition costs, even subject to refund, until such time as the Commission has issued a final order on the merits of the pipeline's compliance filing in which the Commission makes findings that the pipeline is in full compliance with the requirements of Order Nos. 636 and 636-A.

UDC requests that the Commission not allow pipelines to begin recovering potential, estimated transition costs through their compliance filings. UDC states that the Commission should clarify that the pipeline may not recover transition costs from its customers until those costs are actually incurred, unless the parties otherwise agree.

LILCO also requests clarification that GSR costs are only recoverable after they have been incurred, but also requests that if pipelines are allowed to recover estimated (but not yet incurred) GSR costs, interest not be allowed on the unpaid balance of any such estimated costs.

GSR costs must be actually incurred, or known and measurable with reasonable accuracy, in order to qualify for recovery by the pipeline.[230] Pipelines may not begin recovery of any transition costs under Order No. 636, even subject to refund, until after the Commission has found the pipeline to be in full compliance with the requirements of Order Nos. 636 and 636-A. Finally, pipelines will not be permitted to recover interest on the unpaid balance of any estimated GSR costs.

Pipelines should not make filings to begin recovery of their

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230. For purposes of recovering GSR costs, the Commission will consider reasonable variations from the test year requirements utilized in general section 4 rate cases.

GSR costs until after the Commission has approved the recovery mechanisms for such costs included in their restructuring compliance filings. When the Commission rules on a compliance filing, it will specify a prospective date when the tariff sheets implementing restructured services will become effective. Pipelines will then have an opportunity to make a limited section 4 filing to begin recovery of actual GSR costs, under the approved mechanism, contemporaneously with the implementation of the restructured services.

d. Small customers

Tennessee and Columbia Small Customers allege that the Commission erred in Order No. 636-A in refusing to reduce small customers' responsibility for transition costs by 50 percent, consistent with the small customer protection mechanism established in Order No. 528-A. They argue that Order No. 636-A does not go far enough to mitigate the negative impact of Order No. 636 on small customers.

Order No. 636-A significantly modified the final rule to ensure the ability of small customers to secure the benefits of restructuring and to mitigate adverse effects. The additional mitigation of a 50 percent reduction in transition costs for *every* small customer on *every* pipeline system is not warranted. However, pipelines and parties in the restructuring proceedings on particular systems may consider such additional mitigation mechanisms they may agree may be appropriate.

e. Refund provision

NJBRC advocates that there be no interim collection of transition costs, subject to refund. NJBRC argues that, in light

of recent federal court actions in the Columbia bankruptcy proceeding, allowing such recovery prior to a final decision on any challenges to eligibility or prudence will place ratepayers' monies too much at risk. As a general matter, under section 4(e) of the NGA, pipelines are entitled to begin recovering their filed rates, subject to refund, at the end of any suspension period, if the Commission has not rendered a final decision of the justness and reasonableness of the changed rates. Section 4(e) also provides that a pipeline may be required to furnish a bond to ensure the payment of refunds of rate increases collected subject to refund. Parties may petition the Commission to require such a bond where the circumstances might warrant it. The Commission will endeavor to process the filings as quickly as possible (as contemplated by NGA section 4) to try to minimize the length of time rates are collected subject to refund.

f. Direct billing of Account No. 858 costs

LILCO argues that the Commission erred in permitting Account No. 858 transition costs to be direct billed in the same manner as Account No. 191 costs instead of requiring them to be treated like other GSR costs.[231] According to LILCO, prudently incurred, eligible, upstream-pipeline GSR costs incurred by the downstream pipeline are no different from its own GSR costs and should be recovered no differently.

United asserts that in Order No. 636, the Commission classified Account No. 858 costs that could not be directly allocated to customers of unbundled services as "stranded costs." United requests clarification that Order No. 636-A supersedes Order No. 636 on this point, and that pipelines may direct bill Account No. 858 balances to their own customers.

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231. LILCO cites Order No. 636-A at p. 30,655.

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Both LILCO and United misconstrue what the Commission said in Order No. 636-A. The Commission addressed an issue raised by National Fuel concerning pipelines with Account No. 858 trackers, namely, how may a pipeline recover an unrecovered positive balance in such a tracking account upon termination of the tracker? Such a situation is precisely analogous to unrecovered balances in Account No. 191 upon termination of a PGA mechanism, and the Commission provided for direct billing of such balances in both situations. The Commission was not authorizing direct billing of upstream pipeline GSR costs or future Account No. 858 costs that become "stranded" in the course of restructuring. How these costs will be recovered will be dealt with on a case-by-case basis.

g. Avoiding multiple GSR charges

Producer Associations argue that short-haul, production-area transportation, and transportation to pooling points and market centers, should be exempt from GSR recovery programs. Otherwise, they argue, transportation arrangements will be subject to multiple assessments of GSR surcharges that will often discourage the use of the most efficient path to market. Producer Associations cite the Commission's policy of not permitting multiple assessments of Gas Research Institute surcharges as precedent for its proposal.

The Commission will not permit exemption of short-haul, production-area transportation, or transportation to pooling points and market centers from GSR surcharges. Such exemptions would frustrate realization of the Commission's goal of spreading transition costs equitably over a broad customer base. However, pipelines and affected parties in the restructuring proceedings should design mileage-sensitive surcharges, so that

shippers that use only a portion of the pipeline do not pay a disproportionate share of surcharges.[232]

h. Default under an assigned supply contract

Enron seeks clarification that the pipeline must be able to negotiate, as part of the terms and conditions of assigning supply contracts to its customers, a means to recover GSR costs attributable to a customer's default under the assigned contract, where the pipeline remains liable to the producer. Otherwise, according to Enron, the pipeline could be in a "catch-22" situation because the customers could take assignment of such contracts and subsequently elect not to perform under such contracts.

In Order No. 636-A, the Commission stated that the details of responsibility for transition costs of customers that accept assignment of gas supply contracts, in comparison with those that do not, must be worked out in the restructuring proceedings.[233] The Commission will consider any reasonable provisions the pipelines and their customers can negotiate to protect the pipeline in the event of a default on an assigned contract.

i. Recovery of GSR costs from rates for storage service

PSE&G seeks clarification that in the absence of any

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232. *See* Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout or Buydown Costs, 54 FERC ¶ 61,095 at p. 61,301 (1991)(Order No. 528-A).

233. Order No. 636-A at p. 30,660.

connection between cost causation and cost incurrence, transition cost surcharges designed to recover GSR costs will not be assessed against storage services, even though storage is now defined as transportation under Part 284. PSE&G argues that there is no connection between a pipeline's incurrence of such costs and its provision of storage service, and that, since storage customers will already be assessed GSR costs in connection with their transportation to and from storage facilities, no additional assessments for storage service are warranted.

Nothing in Order No. 636 or 636-A requires pipelines to impose demand surcharges for the recovery of GSR costs on unbundled storage service. If a pipeline proposes to impose such a surcharge on storage service, it should explain why the surcharge on transportation to and from the storage facility does not recover a fair share of the GSR costs from the storage customers.

j. Great Plains synthetic gas

Northern Natural, Transwestern, and Florida Gas (collectively referred to as Enron) request that Order No. 636-A be clarified to reflect that the costs of the Great Plains Gasification Project may not be allocated to NGA section 7(c) shippers. Enron asserts that section 7(c) customers clearly did not cause or were not benefitted by contracts involving the Great Plains synthetic natural gas. Enron asserts that the Great Plains costs have consistently been treated as gas supply costs, while the section 7(c) customers merely utilized the pipeline for transportation. Enron asserts that, in many instances, these costs will be recovered from customers who did not even utilize the pipeline out of the Great Plains project, and that since the 7(c) transporters neither caused nor benefitted from the Great Plains

project, allocating costs associated with Great Plains to those transporters would only distort the market signals between supply and demand.

In Order No. 636-A, the Commission clarified that it would consider *any* reasonable proposal by the pipelines that purchase Great Plains gas for recovery of the costs of that gas, whether or not modeled on the proposal approved in a Transco settlement.[234] If any of the pipelines that purchase Great Plains gas propose to recover the costs of such gas from transportation rates for service under individual section 7(c) certificates, the Commission will consider any arguments for or against such recovery in the proceeding where the proposal is made.

k. Triennial rate review

New England Power and ConEd assert that the Commission erred by not requiring pipelines to be subject to a three-year rate review. New England Power asserts that the elimination of the triennial rate review requirement allows pipelines, once rates are in place, to sit back and watch their rates of return on equity rapidly escalate, with no corresponding obligation or incentive to refile and reduce their rates. New England Power asserts that unless the Commission institutes remedial measures on rehearing, natural gas consumers will not be sufficiently protected from pipelines' excessive transportation rates. New England Power and ConEd assert that the section 5 complaint procedure is by itself inadequate protection because its remedy is prospective only. Finally, New England Power asserts that the Commission has the authority to require periodic section 4 filings as a condition of some other benefit voluntarily accepted

234. Order No. 636-A at p. 30,658.

by the pipeline. It asserts that the numerous benefits conferred on pipelines by the Order No. 636 regulatory scheme, such as transition cost recovery and SFV rate design, justify imposition of a periodic rate filing requirement.

ConEd asserts that in rejecting requests to maintain the three year rate review, the Commission failed to adequately explain how a change from cost-based to market-based rates reduces the need for periodic Commission review of a pipeline's non-gas rates. ConEd asserts that, as with the PGA mechanism, market-based sales rates similarly provide a pipeline with the opportunity to change only one cost element of its rates outside of a general section 4 rate proceeding. Finally, ConEd asserts that a rate design which virtually assures a pipeline full cost recovery regardless of the actual level or quality of service that it provides, *i.e.*, SFV, cries out for greater Commission oversight, not a relaxation of the current rate review process.

It is unnecessary for the Commission to attempt to replicate the triennial rate review provisions of the PGA regulations when pipelines terminate their PGAs. In any event, there are limits to the authority of the Commission to require pipelines to periodically justify their existing rate levels.[235] However, as the Commission stated in Order No. 636-A, the procedures provided under NGA sections 4 and 5 should ensure that a pipeline's rates are just and reasonable under ordinary circumstances, and the Commission intends to exercise its powers under those sections to the fullest. In circumstances where there are reasonable expectations of declining costs over the long run,

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235. Public Service Commission of New York (PSCNY) v. FERC, 866 F.2d 487 (D.C. Cir. 1989)(requiring periodic filings under NGA section 4 beyond Commission's statutory authority).

ratemaking methods are available to establish rates that will not over-recover those costs.[236] Furthermore, parties may negotiate for a pipeline's agreement to file section 4 rate proceedings periodically, or by a date certain.[237]

l. Filing of Firm Transportation Service Agreements

APGA requests the Commission to amend the regulations to require pipelines to file their firm transportation service agreements with the Commission or make them available to customers, in order to assure that pipelines treat their customers in a non-discriminatory fashion. APGA states that the Commission has, for example, stated that pipleines must offer evergreen provisions on a non-discriminatory basis, but has not provided a means of determining whether the pipleines are complying with this requirement.

The prohibition against discriminatory practices is not a new requirement imposed by Order No. 636, but has always been a requirement under Part 284 of the regulations. The Commission eliminated the requirement that pipelines file copies of their service agreements in 1989[238] and has received no complaints since then, nor is there any basis for concluding

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236. *See* Ozark Gas Transmission System, 50 FERC ¶ 61,252 (1990)(order on remand from PSCNY v. FERC, *supra*), *order on reh'g*, 53 FERC ¶ 61,451 (1990).

237. Ozark Gas Transmission System, 55 FERC ¶ 61,360 (1991).

238. Final Regulations Clarifying the Filing Obligations for Part 284 Transportation and Sale of Natural Gas, FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,864.

that a reinstatement of the requirement is necessary to ensure compliance with the prohibitions against discrimination. However, pipelines should make these contracts available upon request so that interested parties can be assured of compliance.

C. Confidentiality of Discovery Data

Rochester filed a motion for clarification of the Commission's June 24, 1992 order in these proceedings relating to the use of discovery procedures in the pipeline restructuring proceedings.[239] Rochester asserts that some pipelines submitting discovery data to the parties and Commission staff have claimed that such material is privileged and confidential pursuant to Rule 602(e)(2) of the Commission's Rules of Practice and Procedure, which provides that an offer of settlement that is not approved by the Commission, and any comment on that offer, is not admissible in evidence against any participant who objects to its admission. Rochester argues that data and material submitted in response to the staff's data requests in restructuring proceedings are not subject to the provisions of Rule 602(e)(2) because they are not offers of settlements or comments on such offers.

The Commission grants the requested clarification. Data and material submitted pursuant to staff data requests in a restructuring proceeding prior to the date the pipeline files its compliance filing are not subject to the provisions of Rule 602(e)(2). Section 388.112 of the Commission's regulations is the relevant provision governing the treatment of material submitted to the Commission under a claim of privilege or confidentiality. Parties may negotiate their own protective

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239. 59 FERC ¶ 61,351 (1992).

agreements regarding information exchanged between the pipelines and parties in the restructuring proceedings. However, the information exchanged in such proceedings is not for the purpose of settlement, but to assure that the pipeline has complied with the Commission's orders.

IX. CONCLUSION

With this order, the Commission ends this rulemaking process. The regulations governing the historic restructuring of the natural gas pipeline industry are now final. No further petitions for rehearing of Order No. 636-B will be considered. The Commission intends now to turn its attention and resources to processing each pipeline's compliance filing as quickly as possible so that gas consumers throughout the nation can begin to realize the competitive benefits of a restructured gas industry.

The Commission orders:

Order Nos. 636 and 636-A, and the June 24, 1992 order in this proceeding, are clarified as set forth in this order, and rehearing of Order No. 636-A is denied.

By the Commission. Commissioner Moler dissented in part with a separate statement attached.

(SEAL)

Lois D. Cashell,
Secretary.

Appendix D

APPENDIX

Allied-Signal, Inc. — (Allied-Signal)

American Gas Association — (AGA)

American Natural Gas Corporation and National Energy Systems Company — (American Natural Gas)

American Paper Institute, Inc. — (American Paper Institute)

ANR Pipeline Company — (ANR)

Arcadian Fertilizer, L.P. - (Arcadian)

Arkla, Inc. - (Arkla)

Associated Gas Distributors — (AGD)

Atlanta Gas Light Company and Chattanooga Gas Company — (Atlanta Gas)

BarClays Bank, PLC, Canadian Imperial Bank of Commerce, Credit Lyonnnais and The Fuji Bank, Ltd. — (Barclays)

Blue Flame Suppliers, Corporation — (Blue Flame)

Brooklyn Union Gas Company — (Brooklyn Union)

Cincinnati Gas & Electric Company, The Union Light, Heat and Power Company, Lawrenceburg Gas Company and Mountaineer Gas Company — (Cincinnati Gas)

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Citizens Gas & Coke Utility — (Citizens Gas)

CNG Transmission Corporation — (CNG)

Colorado Interstate Gas Company (CIG)

Columbia Gas Transmission Corporation — (Columbia)

Consolidated Edison Company of New York, Inc. — (ConEd)

Consolidated Minerals, Inc., Georgia-Pacific Corporation, Rinker Materials Corporation, and U.S. Agri-Chemicals Corporation — (Consolidated Minerals)

East Tennessee Group and The Tennessee Valley Municipal Gas Association — (TVMGA)

Elizabethtown Gas Company — (Elizabethtown)

Florida Municipal Natural Gas Association — (FMNGA)

Fuel Managers Association

Great Lakes Gas Transmission Limited Partnership — (Great Lakes)

Industrial Groups — (Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufactures Association, and California League of Food Processors)

Interstate Natural Gas Association of America — (INGAA)

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Interstate Power Company — (Interstate Power)

JMC Power Projects

K N Energy, Inc. — (K N)

Long Island Lighting Company — (LILCO)

Louisville Gas and Electric Company — (Louisville)

Memphis Light, Gas and Water Division, City of Memphis, Tennessee, Philadelphia Gas Works, and The American Public Gas Association — (APGA)

Meridian Oil Inc. — (Meridian)

Midland Cogeneration Venture Limited Partnership — (Midland Cogeneration)

Missouri Public Service, Kansas Public Service, Michigan Gas Utilities, & Peoples Natural Gas Company, Divisions of UtiliCorp United Inc. — (UtiliCorp Divisions)

Missouri Public Service, Kansas Public Service, & Peoples Natural Gas Company, Divisions of UtiliCorp United Inc. — (Indicated UtiliCorp Divisions)

Mojave Pipeline Company — (Mojave)

Municipal Gas Authority of Georgia

National Association of Gas Consumers — (Gas Consumers)

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National Fuel Gas Supply Corporation — (National Fuel)

Natural Gas Pipeline Company of America — (Natural)

NERCO Oil & Gas, Inc. — (NERCO)

New England Gas Distributors — (New England Gas)

New England Power Company — (New England Power)

New Jersey Board of Regulatory Commissioners — (NJBRC)

New Jersey Natural Gas Company — (New Jersey Natural)

New York State Electric & Gas Corporation — (NYSE&G)

Northeast Energy Associates and North Jersey Energy Associates (Northeast Energy)

Northern Distributor Group

Northern Indiana Public Service Company — (Northern Indiana)

Northern Natural Gas Company (Northern), Transwestern Pipeline Company (Transwestern), and Florida Gas Transmission Company (Florida Gas) — (Enron)

Northern States Power Company and Northern States Power Company — (Northern States)

Pacific Gas and Electric Company — (PG&E)

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Pacific Gas Transmission Company — (PGT)

Pacific Interstate Offshore Company (PIOC)

Pacific Offshore Pipeline Company — (POPCO)

Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company and Trunkline Gas Company — (PEC Pipeline Group)

Peoples Gas Light and Coke Company, North Shore Gas Company and Northern Illinois Gas Company — (Peoples Gas)

Power Authority of the State of New York — (Power Authority)

Prior Energy Corporation — (Prior Energy)

Producer Associations — (Independent Petroleum Association of America, Independent Petroleum Association of New Mexico, Louisiana Association of Independent Producers and Royalty Owners, Ohio Oil & Gas Association, Oklahoma Independent Petroleum Association, and Panhandle Producers and Royalty Owners Association)

Public Service Electric and Gas Company and New Jersey Natural Gas Company — (PSE&G)

Questar Pipeline Company — (Questar)

Rochester Gas and Electric Corporation — (Rochester)

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Sierra Pacific Power Company — (Sierra)

Southern California Edison Company — (SoCal Edison)

Southern Natural Gas Company — (Southern)

Southwest Gas Corporation — (Southwest Gas)

State Regulatory Commissions — (Iowa, Missouri, and Wisconsin) (State Commissions)

Tenneco Gas - (Tennecc)

Tennessee Small General Service Customer Group & the Columbia Small Customer Group — (Tennessee and Columbia Small Customers)

TransCanada Pipelines Limited — (TransCanada)

Transcontinental Gas Pipeline Corporation — (Transco)

UGI Utilities, Inc. (UGI)

United Cities Gas Company — (United Cities)

United Distribution Companies (UDC)

United Gas Pipe Line Company — (United)

Virginia Electric and Power Company — (Virginia Power)

Washington Gas Light Company — (Washington Gas)

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Western Resources, Inc. (Western Resources)

Williams Gas Marketing Company — (WGM)

Williston Basin Interstate Pipeline Company — (Williston)

Appendix D

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-004

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-069

Regulation of Natural Gas Pipelines After Wellhead Decontrol

(Issued November 27, 1992)

MOLER, Commissioner, *dissenting in part*:

I will not reiterate the points I made in my dissent to Order No. 636-A. However, a new issue is starkly presented to the Commission in this order, and I disagree with how my colleagues have resolved it.

In Order No. 636-A we permitted small customers to continue their historical right to a one-part rate. On rehearing the small customers have pointed out that a right to capacity at a one-part rate on the downstream pipeline does not go far enough. They seek one-part rates all the way to the wellhead. In response to their request, the Commission leaves the issue of small customer rates on upstream pipelines to the vagaries of the restructuring proceedings. I disagree with that approach.

By limiting the right to a small customer rate to customers "directly connected to" a pipeline, the majority has decided in

this order that a small customer may not have access back to the wellhead. Moreover, the upstream capacity may also cost substantially more. This is because the small customer (which has in the past paid Account No. 858 costs as a volumetric charge) may have to pay a two-part rate, with a reservation charge, to get upstream access. I will closely watch how this issue plays out in the restructuring proceedings.

For this reason, I must dissent in part.

Elizabeth Anne Moler
Commissioner

APPENDIX E — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636-C", *NOTICE OF DENIAL OF REH'G*, 62 F.E.R.C. ¶ 61,007 (1993)

Commission Opinions, Orders and Notices

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Docket No. RM91-11-005

Docket No. RM87-34-070

62 FERC ¶ 61,007 (1993)

ORDER NO. 636-C

Notice of Denial of Rehearing

(Issued January 8, 1993)

By Direction of the Commission: Lois D. Cashell, Secretary.

In Order No. 636-B, the Commission stated that "[n]o further petitions for rehearing of Order No. 636-B will be considered." Therefore, take notice that the Commission has determined to take no action on the requests for rehearing of Order No. 636-B,[1] filed by Elizabethtown Gas Company,

1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas (Cont'd)

Appendix E

Piedmont Natural Gas Company, TransCanada PipeLines Limited, Cascade Natural Gas Corporation, Washington Natural Gas Company, and the Washington Power Company, Western Tennessee Municipal Group and Kentucky Cities, Meridian Oil, Inc., UGI Utilities, Inc., Michigan Gas Utilities, Missouri Public Service, Brooklyn Union Gas Company, Kansas Public Service and Peoples Natural Gas Company, Divisions of Utilicorp United, Inc., KN Customer Group, Mississippi River Transmission Corporation, the PEC Pipeline Group (Algonquin Gas Transmission Company, Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Corporation, and Trunkline Gas Company), Long Island Lighting Company, the East Tennessee Group and the Tennessee Valley Municipal Association, Hadson Gas Systems, Inc., Leviathan Gas Pipeline Company, National Fuel Gas Distribution Corporation, the Missouri Public Service Commission, the New England Gas Distributors, and the Associated Gas Distributors.

Accordingly, the requests for rehearing are deemed denied under section 19(a) of the Natural Gas Act[2] and rule 713(f) of the Commission's Rules of Practice and Procedure.[3]

(Cont'd)

Pipelines After Partial Wellhead Decontrol, 57 Fed. Reg. 13,267 (April 16, 1992), FERC Statutes and Regulations P 30,939 (April 8, 1992), reh'g granted and denied in part, Order No. 636-A, 57 Fed. Reg. 36,128 (August 12, 1992), FERC Statutes and Regulations P 30,950 (August 3, 1992), order on reh'g, Order No. 636-B, 57 Fed. Reg. 57,911 (December 8, 1992), 61 FERC P 61,272 (1992).

2. 15 U.S.C. § 717r.

3. 18 C.F.R. § 385.713(f) (1992).

APPENDIX F — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER MODIFYING OPINION (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

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and consolidated cases

Before: WALD, SENTELLE and ROGERS, *Circuit Judges.*

ORDER

It is **ORDERED**, by the Court, on its own motion, that the opinion filed herein on July 16, 1996, is amended, as follows:

At page 72:

Delete footnote 62

and substitute therefor new footnote 62, as follows:

Appendix F

The LDCs briefly argue that NGA § 1(c), the so-called "Hinshaw exemption," deprives the Commission of jurisdiction over their capacity sales to their own end-users. In this regard, they refer us to Congress' determination in § 1(c) that certain pipelines are "matters primarily of local concern and subject to regulation by the several States." 15 U.S.C. § 717(c). For the reasons set out in the text, however, the Commission's authority to regulate capacity release arises from its jurisdiction over the interstate pipeline that consummates the transaction and the subject of the transaction, the interstate transportation of gas, entirely independent of its jurisdiction over the releasing or replacement shipper. Accordingly, we reject the LDCs' claim, given that they do not suggest that FERC has improperly exercised jurisdiction over the release of capacity held on nonjurisdictional Hinshaw pipelines.

Per Curiam
FOR THE COURT:
Mark J. Langer, Clerk

s/ illegible
Deputy Clerk

APPENDIX G — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER DENYING PETITIONS FOR REHEARING (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

Windward Energy and Marketing Company, et al.,

Intervenors

Consolidated with 92-1495, 92-1496, 94-1171, 94-1173, 94-1174, 94-1175, 94-1176, 94-1177, 94-1178, 94-1179, 94-1180, 94-1181, 94-1183, 94-1184, 94-1185, 94-1187, 94-1188, 94-1189, 94-1190, 94-1193, 94-1194, 94-1196, 94-1197, 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231, 94-1232, 94-1233, 94-1234, 94-1236, 94-1237, 94-1238, 94-1239, 94-1240, 94-1241, 94-1242, 94-1243, 94-1246, 94-1247, 94-1248, 94-1249, 94-1252, 94-1256, 94-1257, 94-1258, 94-1259, 94-1263, 94-1264, 94-1265, 94-1267, 94-1270

Appendix G

BEFORE: Wald, Sentelle and Rogers, Circuit Judges

ORDER

Upon consideration of the petitions for rehearing of the Atlanta Gas Light Company, et al. and Associated Gas Distributors, et al., and of the response thereto, it is

ORDERED that the petitions be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

s/ Robert A. Bonner
Robert A. Bonner

APPENDIX H — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER DENYING SUGGESTIONS FOR REHEARING *IN BANC* (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

Windward Energy and Marketing Company, et al.,

Intervenors

Consolidated with 92-1495, 92-1496, 94-1171, 94-1173, 94-1174, 94-1175, 94-1176, 94-1177, 94-1178, 94-1179, 94-1180, 94-1181, 94-1183, 94-1184, 94-1185, 94-1187, 94-1188, 94-1189, 94-1190, 94-1193, 94-1194, 94-1196, 94-1197, 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231, 94-1232, 94-1233, 94-1234, 94-1236, 94-1237, 94-1238, 94-1239, 94-1240, 94-1241, 94-1242, 94-1243, 94-1246, 94-1247, 94-1248, 94-1249, 94-1252, 94-1256, 94-1257, 94-1258, 94-1259, 94-1263, 94-1264, 94-1265, 94-1267, 94-1270

Appendix H

BEFORE: Edwards, Chief Judge; Wald, Silberman, Williams, Ginsburg, Sentelle, Henderson, Randolph, Rogers and Tatel, Circuit Judges

ORDER

Upon consideration of the Suggestions for Rehearing *In Banc* of the Atlanta Gas Light Company, et al, and of Associated Gas Distributors, et al., the response thereto, and the absence of a request by any member of the court for a vote, it is

ORDERED that the suggestions be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

s/ Robert A. Bonner
Robert A. Bonner
Deputy Clerk

Circuit Judges Silberman and Henderson did not participate in this order.

APPENDIX I — SECTION 1 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717 (1994)

15 U.S.C.A. § 717

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B — NATURAL GAS

§ 717. Regulation of natural gas companies

(a) Necessity of regulation in public interest

As disclosed in reports of the Federal Trade Commission made pursuant to S.Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.

(b) Transactions to which provisions of chapter applicable

The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and

to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

(c) Intrastate transactions exempt from provisions of chapter; certification from State commission as conclusive evidence

The provisions of this chapter shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this chapter by this subsection are declared to be matters primarily of local concern and subject to regulation by the several States. A certification from such State commission to the Federal Power Commission that such State commission has regulatory jurisdiction over rates and service of such person and

facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction.

(d) Vehicular natural gas jurisdiction

The provisions of this chapter shall not apply to any person solely by reason of, or with respect to, any sale or transportation of vehicular natural gas if such person is—

(1) not otherwise a natural-gas company; or

(2) subject primarily to regulation by a State commission, whether or not such State commission has, or is exercising, jurisdiction over the sale, sale for resale, or transportation of vehicular natural gas.

APPENDIX J — SECTION 2 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717a (1994)

15 U.S.C.A. § 717a

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717a. Definitions

When used in this chapter, unless the context otherwise requires —

(1) "Person" includes an individual or a corporation.

(2) "Corporation" includes any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, receiver or receivers, trustee or trustees of any of the foregoing, but shall not include municipalities as hereinafter defined.

(3) "Municipality" means a city, county, or other political subdivision or agency of a State.

(4) "State" means a State admitted to the Union, the District of Columbia, and any organized Territory of the United States.

(5) "Natural gas" means either natural gas

unmixed, or any mixture of natural and artificial gas.

(6) "Natural-gas company" means a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale.

(7) "Interstate commerce" means commerce between any point in a State and any point outside thereof, or between points within the same State but through any place outside thereof, but only insofar as such commerce takes place within the United States.

(8) "State commission" means the regulatory body of the State or municipality having jurisdiction to regulate rates and charges for the sale of natural gas to consumers within the State or municipality.

(9) "Commission" and "Commissioner" means the Federal Power Commission, and a member thereof, respectively.

(10) "Vehicular natural gas" means natural gas that is ultimately used as a fuel in a self-propelled vehicle.

APPENDIX K — SECTION 4 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717c (1994)

15 U.S.C.A. § 717c

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717c. Rates and charges

(a) Just and reasonable rates and charges

All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.

(b) Undue preferences and unreasonable rates and charges prohibited

No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges,

service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Filing of rates and charges with Commission; public inspection of schedules

Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from June 21, 1938) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Changes in rates and charges; notice to Commission

Unless the Commission otherwise orders, no change shall be made by any natural-gas company in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after thirty days' notice to the Commission and to the public. Such notice shall be given

by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the thirty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Authority of Commission to hold hearings concerning new schedule of rates

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint of any State, municipality, State commission or gas distributing company, or upon its own initiative without complaint, at once, and if it so orders, without answer or formal pleading by the natural-gas company, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the natural-gas company affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule

and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate, charge, classification, or service shall go into effect. Where increased rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission, to keep accurate accounts in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts were paid, and, upon completion of the hearing and decision, to order such natural-gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon

the natural-gas company, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

APPENDIX L — SECTION 5 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717d (1994)

15 U.S.C.A. § 717d

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717d. Fixing rates and charges; determination of cost of production or transportation

(a) Decreases in rates

Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: Provided, however, That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such

natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates.

(b) Costs of production and transportation

The Commission upon its own motion, or upon the request of any State commission, whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transportation of natural gas by a natural-gas company in cases where the Commission has no authority to establish a rate governing the transportation or sale of such natural gas.

APPENDIX M — SECTION 7 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717f (1994)

15 U.S.C.A. § 717f

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717f. Construction, extension, or abandonment of facilities

(a) Extension or improvement of facilities on order of court; notice and hearing

Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: Provided, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas

company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) Abandonment of facilities or services; approval of Commission

No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) Certificate of public convenience and necessity

(1)(A) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there

is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: Provided, however, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

(B) In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: Provided, however, that the Commission may issue a

temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of —

(A) natural gas sold by the producer to such person; and

(B) natural gas produced by such person.

(d) Application for certificate of public convenience and necessity Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Granting of certificate of public convenience and necessity

Except in the cases governed by the provisos contained in subsection (c) (1) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) Determination of service area; jurisdiction of transportation to ultimate consumers

(1) The Commission, after a hearing had

upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization; and (2) If the Commission has determined a service area pursuant to this subsection, transportation to ultimate consumers in such service area by the holder of such service area determination, even if across State lines, shall be subject to the exclusive jurisdiction of the State commission in the State in which the gas is consumed. This section shall not apply to the transportation of natural gas to another natural gas company.

(g) Certificate of public convenience and necessity for service of area already being served

Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) Right of eminent domain for construction of pipelines, etc.

Appendix M

When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the property is situated:

Provided, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000.

(4) (2) (2)

Nos. 96-1186, 96-1187 and 96-1188

Supreme Court, U.S.
FILED
FEB 27 1997
OFFICE OF THE CLERK

IN THE

Supreme Court of the United States

OCTOBER TERM, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,
Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION and
UNITED STATES OF AMERICA,
Respondents.

On Petition for Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

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BRIEF IN OPPOSITION OF RESPONDENTS PROCESS GAS CONSUMERS GROUP, AMERICAN IRON AND STEEL INSTITUTE AND GEORGIA INDUSTRIAL GROUP

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31 pp

QUESTION PRESENTED

Whether the United States Court of Appeals for the District of Columbia Circuit correctly held that the Federal Energy Regulatory Commission ("FERC") did not exceed its jurisdiction under Natural Gas Act Section 1(b), 15 U.S.C.§ 717(b), Pet. App. at 1007a-1008a, to regulate the transportation of natural gas in interstate commerce by requiring the reallocation of interstate pipeline capacity between a local distribution company and its customers, or by a municipality, to comply with FERC's capacity release regulations.

RULE 29.6 LISTING

The Process Gas Consumers Group ("PGC") is an association of industrial consumers of natural gas organized to promote the development and adoption of coordinated, rational and consistent federal and state policies affecting industrial gas users. PGC members own and operate hundreds of manufacturing plants located throughout the United States. PGC has no parent or subsidiary companies.

The American Iron and Steel Institute ("AISI") is the principal trade association of the domestic steel industry. Its 35 domestic members account for approximately two-thirds of the raw steel production capability in the United States. AISI has no parent or subsidiary companies.

The Georgia Industrial Group ("GIG") is an association of industrial users of natural gas located in the states of Georgia and Alabama. GIG actively participates in variety of state and federal proceedings affecting the price of natural gas and electricity in the states of Georgia and Alabama. GIG has no parent or subsidiary companies.

Members of PGC, AISI and GIG consume substantial quantities of natural gas delivered through interstate natural gas pipelines.

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The Process Gas Consumers Group, American Iron & Steel Institute, and the Georgia Industrial Group, Respondents in the captioned cases, respectfully request that this Court deny the petitions for a writ of certiorari to review the judgment of the United States Court of Appeals for the District of Columbia Circuit (reported at 88 F.3d 1105 (1996)(Pet. App. at 1a to 174a)), submitted by local distribution companies ("LDCs") in No. 96-1186, state regulatory agencies ("PSCs") in No. 96-1188, and municipalities that own local distribution facilities ("municipalities") in 96-1187.

STATEMENT OF THE CASE

The Natural Gas Act ("NGA"), 15 U.S.C. § 717 et seq., provides the basic framework for regulation of the natural gas industry. Since 1978, the regulation of interstate transportation and sales for resale by interstate pipelines has undergone dramatic change. [1/]

Regulatory initiatives undertaken by the Federal Energy Regulatory Commission ("FERC") have "unbundled" the sales and transportation services formerly provided in "package" form by interstate pipelines. At the heart of that unbundling is the requirement of "open access" interstate transportation, which is based on the NGA's prohibition against "unduly discriminatory or preferential" rates or terms of pipeline services. 15 U.S.C. §§ 717c(b) and 717d(a). These initiatives

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1/ The court of appeals decision aptly described this regulatory evolution as having "gradually withdrawn from direct regulation of certain industry sectors in favor of a policy of 'light-handed regulation' when market forces make that possible." Pet. App. at 6a. Prior to 1978, producers typically sold gas to federally-regulated, interstate natural gas pipelines who, in turn, provided a combined, or "bundled," transportation/gas sales service to LDCs. The LDCs then provided a state-regulated, bundled retail sales/transportation service to end-users of natural gas.

enable all interested shippers -- including LDCs, end-users, producers and gas marketers -- to contract for interstate transportation of gas among virtually any combination of receipt and delivery points on an interstate pipeline. As a result, LDCs, producers, marketers and end-users are able to sell, buy and ship natural gas virtually anywhere on the interstate transportation grid. A dynamic, integrated national market for natural gas has emerged, complete with a vibrant futures market, actively traded regional markets, and a "secondary market" for interstate transportation rights. At the retail level, many States have implemented similar unbundling programs for LDC sales and transportation services.[2/]

1. **The Natural Gas Policy Act of 1978.**

Congress took the first step away from the bundled service approach in 1978 by enacting the Natural Gas Policy Act ("NGPA"). 15 U.S.C. § 3301 *et seq.*. The NGPA phased out regulation of wellhead prices charged by natural gas producers. As this Court recently observed, the NGPA also was designed to "promote gas transportation by interstate and intrastate pipelines." *General Motors Corp. v. Tracy*, 1997 U.S. Lexis 692, at *12 (decided February 18, 1997), *quoting* 57 Fed. Reg. 13271 (1992). Thus, with the NGPA, Congress began the process of introducing greater competition into natural gas markets by separating interstate pipelines' sales and transportation functions into discrete services.

2. **FERC Order No. 436.**

In 1985, FERC sought to further the NGPA's goal of a more competitive national wellhead market by promulgating

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2/ *See generally* U.S. Dept. of Energy, Energy Information Administration, "State Regulators Promote Consumer Choice in Retail Gas Markets," *Natural Gas 1996: Issues and Trends*, at 113-124 (Dec. 1996).

Order No. 436.[3/] In Order No. 436, FERC recognized that encouraging competitive gas markets required nondiscriminatory access to interstate pipeline transportation.[4/] Order No. 436 promoted nondiscriminatory access to the national transportation grid by, among other measures, providing "blanket certificates" (as opposed to the contract-specific, NGA Section 7(c) certificate otherwise required) for pipelines willing to provide transportation service pursuant to open access principles. At their core, these principles required interstate transporters to provide access to all shippers on a nondiscriminatory, "first-come, first-served" basis, even if the shipper intended to compete with the transporter in the sale of gas.[5/] In this way, Order No. 436 sought to afford downstream gas purchasers an alternative to buying gas under pipelines' bundled sales/transportation service.

In the wake of Order No. 436, pipelines sought FERC authorization for a variety of "capacity release,"[6/] "capacity

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3/ *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,665 (1985)("Order No. 436").

4/ *Id.* at 31,494-504.

5/ *Id.* at 31,516-518. *See Colorado Interstate Gas Co. v. FERC*, 890 F.2d 1121,1123 (D.C. Cir. 1989).

6/ *See, e.g., Arkla Energy Resources*, 53 FERC ¶ 61,127 (1990); *East Tennessee Natural Gas Company*, 53 FERC ¶ 61,304 (1990); *Florida Gas Transmission Co.*, 51 FERC ¶ 61,309, *order on reh'g*, 53 FERC ¶ 61,396 (1990).

brokering"[7/] and "transportation assignment" programs.[8/] Under such programs, shippers holding interstate pipeline capacity could reallocate their right to use some or all of their pipeline capacity to third-parties. In authorizing capacity brokering and assignment programs, FERC specifically reserved the right to modify or terminate the programs as required by the public convenience and necessity. *See Algonquin Gas Transmission Co.*, 59 FERC ¶ 61,032 at 61,092-93 (1992).[9/]

When Congress completed the deregulation of wellhead prices with passage of the Natural Gas Wellhead Decontrol Act

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7/ *See, e.g., Algonquin Gas Transmission Co.*, 53 FERC ¶ 61,417 (1990); *Columbia Gas Transmission Corp.*, 49 FERC ¶ 61,071 (1989); *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069 (1990).

8/ *See, e.g., CNG Transmission Corp.*, 55 FERC ¶ 61,189 (1991); *Columbia Gas Transmission Corp.*, 49 FERC ¶ 61,071 (1989); *Texas Eastern Transmission Corp.*, 48 FERC ¶ 61,248, *order on reh'g*, 48 FERC ¶ 61,378 (1989), *order on reh'g*, 51 FERC ¶ 61,170, *order on reh'g*, 52 FERC ¶ 61,273 (1990).

9/ Contrary to the PSCs' characterization, FERC did not recognize in *Texas Eastern Transmission Corp.*, 48 FERC ¶ 61,378 at 62,552 (1989)("*Texas Eastern*") that "capacity purchased by LDCs in interstate pipeline facilities should be treated as the LDCs' (not the pipelines') own capacity." PSC Petition at 7. Consistent with "capacity assignment" programs generally, *Texas Eastern* considered reallocation of pipeline capacity held by a second interstate pipeline, Algonquin Gas Transmission Company, not an LDC. Thus, FERC had before it a capacity reallocation issue concerning two entities over which it clearly had jurisdiction; it did not consider whether upstream capacity held by a nonjurisdictional LDC could be considered an "expansion" of that LDC's system. Accordingly, the impression created by the LDCs' replacing the name "Algonquin" with the bracketed words "an LDC's" and "the LDC's" when quoting *Texas Eastern* -- that FERC acknowledged state jurisdiction over interstate capacity held by LDCs -- distorts the meaning of that decision.

of 1989,[10] it urged retention of Order No. 436's "open access" transportation regime. The Congress emphasized that:

> [T]hese new rules, and especially the wide adoption of blanket certificates for nondiscriminatory open access interstate transportation of non-pipeline gas, are essential to its decision to complete the decontrol process.

H.R. Rep. No. 29, 101st Cong., 1st Sess., at 6 (1989). Indeed, Congress encouraged FERC "to retain and improve this competitive structure in order to maximize the benefits of decontrol." *Id.*

3. FERC Order No. 636.

Notwithstanding the partial success of Order No. 436, FERC eventually concluded that shippers purchasing their gas supplies from nonpipeline sources were not receiving the same quality of transportation service as those taking the pipelines' bundled service.[11] This disparity in service quality led FERC to promulgate Order No. 636, which required pipelines

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[10] Pub. L. No. 101-60, 103 Stat. 157 (1989).

[11] *See Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 30,939 at 30,398-407 (Pet. App. at 175a-407a, at 195a-215a), *order on reh'g*, Order No. 636-A, FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 30,950 (Pet. App. 408a-812a), *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992)(Pet. App. 813a-998a), *reh'g denied*, Order No. 636-C, 62 FERC ¶ 61,007 (1993)(Pet App. 999a-1000a).

> to provide all transportation services on a basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier.

Order No. 636, Pet. App. at 182a-183a. With Order No. 636, FERC completed its efforts to establish interstate pipeline transportation capacity and natural gas as separate "commodities" obtainable from different sources. Order No. 636 shifted FERC's regulatory focus away from judging the "comparability" of a pipeline's bundled and unbundled transportation services toward

> ensuring that pipeline transportation of all gas supplies is performed on an equal basis under reasonable transportation terms and conditions that enable buyers to use open access transportation to maximize the benefits of a competitive wellhead natural gas market.

Id. at 234a.

As part of Order No. 636's pro-competitive regulatory initiatives, FERC established a framework to govern pipeline customers' reallocation of interstate pipeline transportation capacity to third parties. Previously, FERC had approved differing capacity release, brokering, and reassignment programs for individual pipelines. In Order No. 636, FERC concluded that a structured, industry-wide program permitting "capacity release" would better serve interstate markets than either a prohibition or a collection of individualized programs:

> First, . . . the Commission no longer believes that it can adequately monitor capacity brokering under existing certificates to ensure that all allocations are nondiscriminatory.

> Simply put, there are too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering as it now exists. Second, the Commission believes that the two new generic allocation of capacity programs it is adopting make the necessary adjustments to eliminate the potential for firm capacity holders to unduly discriminate in their assignment of capacity, and facilitate the development of the secondary transportation market.

Id. at 238a-239a. Order No. 636's "capacity release" provisions permitted holders of unused interstate pipeline capacity to resell that capacity, either temporarily or permanently, to third-parties through a bidding system maintained by the pipeline. FERC explained that its capacity release mechanism "would afford buyers and sellers of firm capacity with one place to shop to ensure that firm capacity is used as efficiently as possible." *Id.* at 245a.

FERC's capacity release regulations, as supplemented by individual pipelines' tariffs, establish procedures for releasing transportation capacity rights and pipelines' execution of contracts with replacement shippers. Releases may be accomplished through bidding on a pipeline-sponsored electronic bulletin board or through "prearranged releases" negotiated between the releasor and replacement customer or through a combination of those procedures. Ultimately, however, while the terms of the release must be acceptable to the releasor, the terms of the release must also be consistent with the pipelines' filed tariffs and the replacement shipper must enter into a contract with the pipeline to receive the

released transportation service.[12/] Unless the release of capacity is permanent, the releasing shipper would remain liable on its contract with the pipeline, but would receive a credit against its bill for the capacity resold. *Id.* at 245a-252a.

4. The Court of Appeals Decision.

Local distribution companies, PSCs, and municipalities that own local distribution facilities sought judicial review of Order No. 636's capacity release regime. The LDCs challenged certain aspects of FERC's jurisdiction over capacity release transactions (Pet. App. at 79a-80a) and, together with the PSCs, argued that such transactions between LDCs and their customers came within the states' jurisdiction over "local distribution." *Id.* at 81a. The municipalities similarly maintained that their capacity release transactions were outside FERC's jurisdiction because municipalities do not come within the definition of a "natural gas company" subject to the NGA. *Id.* at 83a.

In its decision, the United States Court of Appeals for the District of Columbia Circuit rejected all challenges to FERC's capacity release program. The court of appeals found the release of interstate pipeline capacity to constitute an aspect of the interstate transportation of natural gas. The regulations governing such releases "operate as a term or condition of pipeline service, with which its customers must comply." *Id.* at 80a. Moreover, because this Court's decisions under the Commerce Clause precluded state regulation of interstate transportation, the court of appeals found that

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12/ Pipelines' tariffs permit negotiation of some terms, such as contract duration and, within limits, price. That is, the tariff permits a pipeline to charge rates between a filed maximum and a filed minimum, and neither the pipeline nor the releasor may charge rates outside the FERC-approved range.

> the federal government interceded to ensure stability and protect the interests of the consuming public. It thereby occupied the field, which necessarily includes both the sale and resale of interstate transportation rights.

Id. at 81a. Consequently, the court of appeals concluded that regulation of capacity release transactions fell within the exclusive and plenary jurisdiction over interstate transportation granted FERC under the NGA.

Having concluded that capacity release transactions came within FERC's general jurisdiction over interstate transportation, the court of appeals next declined to adopt the limitations on that jurisdiction proposed by the LDCs, PSCs, and municipalities. The court of appeals found that the jurisdiction over "local distribution" granted states by NGA Section 1(b) "does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas," *Id.* at 82a, and concluded that "states have never regulated the terms and conditions of interstate pipeline transportation." *Id.*

With regard to the municipalities' definitional argument, the court of appeals reasoned that "FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas pipelines," *Id.* at 84a, and further observed that "the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers." *Id.* at 85a. The court of appeals found "most persuasive" the analogy between FERC's curtailment regulations and the capacity release program, in that "both involve the pipelines' allocation of transportation capacity among their shippers in compliance with federally mandated strictures." *Id.*

REASONS WHY THE PETITIONS SHOULD BE DENIED

I. Petitioners Have Not Demonstrated a Compelling Reason Justifying This Court's Review of the Court of Appeals Decision.

Rule 10 of this Court's Rules instructs that review on a writ of certiorari is not a matter of right, but of judicial discretion, and will be granted only for "compelling reasons." While not an exhaustive listing, Rule 10 identifies reasons that could prove sufficiently compelling to justify the granting of a writ of certiorari. Examples theoretically applicable to the court of appeals decision at issue include conflicting decisions between United States courts of appeals on an important matter, important federal law questions of first impression requiring resolution by this Court, or a court of appeals decision regarding an important federal question that conflicts with relevant decisions of this Court.

Here, the petitions in Nos. 96-1186, 96-1187, and 96-1188 fail to identify a credible, let alone compelling, reason to justify granting a writ of certiorari. The petitions point to the decision of no other circuits with which the court of appeals decision at issue conflicts. The petitions do not purport to identify an important federal question of first impression requiring resolution by this Court. Nor do the petitions demonstrate a conflict between the court of appeals decision and any decision of this Court concerning an important federal question.

The petitions do not challenge the court of appeals' determination that promulgation of the capacity release program represents a permissible exercise of FERC's jurisdiction over the interstate transportation of natural gas. Instead, the petitions argue more narrowly that FERC exceeded

its jurisdiction in applying its capacity release regulations to releases between LDCs and their customers, and by municipalities. According to one petition:

> As should be clear, this petition presents no challenge to the concept of "unbundling" or the overall objectives of the federal plan. Rather, it concerns only the question of ultimate control over one aspect of the current market structure, the resale of capacity by LDCs to in-state customers.

LDC Petition at 24. The petitions disagree at length with the analytical approach adopted by the court of appeals in resolving their jurisdict ional claims, maintaining that inadequate attention was paid to State regulatory prerogatives preserved by the NGA. LDC Petition at 18-20; PSC Petition at 11-13; Municipalities Petition at 9-12.

The petitions fail to identify an "important federal question" warranting this Court's attention. The narrow jurisdictional arguments posited by the PSCs, LDCs and municipalities rest on the fundamental mischaracterization of capacity release transactions between LDCs and their customers, and by municipalities, as "local distribution services" traditionally provided subject to state or local regulation. In fact, the release of interstate pipeline capacity plainly involves interstate transportation by interstate pipelines, not local distribution service -- as the court of appeals correctly found and the petitions do not contest. The released interstate transportation rights extend across many states -- from Texas and Louisiana to New York and Massachusetts and everywhere in between -- and require a contract between the transporting pipeline and the replacement shipper that acquires the service. Indeed, the ability of LDCs and municipalities to release interstate pipeline capacity directly results from FERC's

regulation of interstate pipeline services, including the unbundling of services offered by interstate pipelines. Consequently, as explained in Section II, *infra*, the release of interstate pipeline capacity by LDCs and municipalities, whether to their customers or any other third party, falls within FERC's exclusive jurisdiction over the interstate transportation of natural gas.

Furthermore, while the petitions occasionally reference this Court's precedents regarding the boundaries of federal and state jurisdiction under the NGA, at no time do they identify a single holding of this Court with which the court of appeals decision purportedly conflicts. Indeed, the municipalities' petition attacks the court of appeals for its supposed failure to adhere to *FERC* precedents, not the prior holdings of this Court. *See* Municipalities Petition at 12-19.

At best, the petitions evidence continuing disagreement with the jurisdictional conclusions reached by the court of appeals; however, mere disagreement with the court of appeals, no matter how deeply felt or forcefully expressed, does not justify review by this Court. Thus, the petitions manifestly fail to present a compelling reason for this Court to review the decision of the court of appeals. Accordingly, the petitions for writ of certiorari in Nos. 96-1186, 96-1187, and 96-1188 should be denied.

II. The Court of Appeals Decision Is Consistent with Both the NGA and This Court's Precedents Regarding the Scope of Federal Jurisdiction Over the Transportation of Natural Gas in Interstate Commerce.

The court of appeals decision is entirely consistent with both the NGA and this Court's prior precedents concerning the jurisdictional boundaries between federal and state regulatory

responsibilities. The NGA subjects the natural gas industry "to interlocking regulation by both federal and state authorities." *Northwest Central Pipeline Corp. v. State Corporation Commission of Kansas*, 489 U.S. 493, 506 (1989)("*Northwest*"). The framework for this "interlocking regulation" is set forth in NGA Sections 1(b) and 1(c). *See* 15 U.S.C. §§ 717(b),(c). NGA Section 1(b) provides, in pertinent part, that the statute's provisions "shall apply to the transportation of natural gas in interstate commerce . . . and to natural-gas companies engaged in such transportation." 15 U.S.C. § 717(b). The NGA

> contemplated the exercise of federal power as specified in the Act, particularly in that interstate segment which the states were powerless to regulate because of the Commerce Clause of the Federal Constitution.

FPC v. Panhandle Eastern Pipe Line Co., 337 U.S. 498, 502-503 (1949).

This Court repeatedly has interpreted Section 1(b)'s grant of federal jurisdiction over interstate transportation as affording "exclusive Federal Energy Regulatory Commission jurisdiction over 'the transportation of natural gas in interstate commerce . . . .'" *Northwest*, 489 U.S. at 510. The Court has declared it "well settled" that "Congress occupied the field of matters relating to . . . transportation of natural gas in interstate commerce." *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 305, (1988)("*Schneidewind*"). *See also FPC v. Louisiana Power & Light Co.*, 406 U.S. 621, 636 (1972)("*Louisiana Power & Light*), *quoting Panhandle Eastern Pipe Line Co. v. Public Service Commission of Indiana*, 332 U.S. 507, 516 (1947)(Congress drew three things "within its own regulatory power, delegated by the Act to its agent, the Federal Power Commission" including "the transportation of natural gas in

interstate commerce"); *FPC v. Panhandle Eastern Pipe Line Co.*, 337 U.S. 498, 503 (1949)(same). In so doing, Congress intended that FERC "regulate comprehensively and effectively the transportation and sale of natural gas, and to achieve the uniformity of regulation which was an objective of the Natural Gas Act." *Northern Natural Gas Co. v. State Corporation Commission of Kansas*, 372 U.S. 84, 91-92 (1963)("*Northern Natural Gas*"). *See also Schneidewind*, 485 U.S. at 310 ("uniformity of regulation . . . was an objective of the Natural Gas Act").

This Court has soundly rejected previous attempts to read into NGA Section 1(b) limitations on FERC's plenary jurisdiction over the interstate transportation of natural gas. In *Louisiana Power & Light*, the Court dismissed the contention that federal jurisdiction over transportation applied only to interstate pipeline "sales for resale" and did not reach "direct sales" by interstate pipelines to end-users. The Court explained that each of the areas reserved to federal jurisdiction by Section 1(b)

> is an independent grant of jurisdiction and, though the Act's application to "sales" is limited to sales of interstate gas for resale, the Act applies to interstate "transportation" regardless of whether the gas transported is ultimately sold retail or wholesale.

406 U.S. at 636. Similarly, in *FPC v. East Ohio Gas Co.*, 338 U.S. 464 (1950)("*East Ohio Gas*"), the Court refused to read the federal jurisdiction over interstate transportation as limited to companies that either transported "gas in interstate commerce for hire or for sales to be followed by resales." *Id.* at 468. According to the Court, "the short answer is that the Act's language did not express any such limitation." *Id.* The Court went on to observe that:

> [T]hroughout the Act "transportation" and "sale" are viewed as separate subjects of regulation. They have independent and equally important places in the Act. Thus, to adopt respondents' construction would unduly restrict the Commission's power to carry out one of the major policies of the Act.

Id. [13/]

Contrary to the LDCs' contention that "the perceived federal need for uniformity must give way to the primacy of state regulation as guaranteed by the Act," LDC Petition at 19, this Court has made clear that state regulation may not impinge upon FERC's ability to achieve the comprehensive regulatory scheme mandated by the NGA. Even where a state purports to regulate within a sphere reserved to its jurisdiction by the NGA, "[s]tate regulation . . . may be pre-empted as conflicting with FERC's authority over interstate transportation . . . if state regulation prevents attainment of FERC's goals." *Northwest*, 489 U.S. at 515-16; *Schneidewind*, 485 U.S. at 299-300. For example, in *Northern Natural Gas*, the Court invalidated certain regulatory orders promulgated by the State of Kansas ostensibly pursuant to its NGA Section 1(b) jurisdiction over "production or gathering." Because the orders at issue required an interstate pipeline to purchase gas in a certain manner, the Court concluded that:

13/ NGA Section 1(c), passed by Congress in response to *East Ohio Gas*, does not alter the scope of FERC's jurisdiction over the interstate transportation of natural gas. This Court recently characterized Section 1(c) as simply a Congressional acknowledgement regarding "the important role of the States in regulating *intrastate* transportation and distribution of natural gas." *General Motors Corp. v. Tracy*, 1997 U.S. Lexis 692, *28 (decided February 18, 1997)(emphasis added).

> These State orders necessarily deal with matters which directly affect the ability of the Federal Power Commission to regulate comprehensively and effectively the transportation and sale of natural gas, and to achieve the uniformity which was an objective of the Natural Gas Act. They therefore invalidly invade the federal agency's exclusive domain.

372 U.S. at 91-92. In such situations, the Court emphasized that "[n]ot the federal but the state regulation must be subordinated, when Congress has so plainly occupied the regulatory field." *Id.* at 93. *See also Schneidewind*, 485 U.S. at 310, *quoting Northern Natural Gas*, 372 U.S. at 91-92 ("prospect of interference with the federal regulatory power" permits pre-emption of state law even though "collision between the state and federal regulation may not be an inevitable consequence").

The language of NGA Section 1(b), and this Court's prior decisions interpreting it, make plain that FERC possesses exclusive jurisdiction to regulate a particular *activity, i.e.* transportation of natural gas in interstate commerce. While Section 1(b) also affords FERC jurisdiction over particular entities engaged in such transportation (*i.e.* "natural-gas companies"), this represents a separate jurisdictional grant that does not modify or constrain FERC's Section 1(b) jurisdiction over interstate transportation of natural gas. In other words, FERC's jurisdiction over the interstate transportation of natural gas *is wholly unrelated to the nature of the entities involved in that activity*. For this reason alone, contentions that capacity release transactions between LDCs and their customers, or by municipalities, lie wholly outside FERC's jurisdiction over interstate transportation, are without merit.

Moreover, the NGA's goal of uniform regulation for the interstate transportation of natural gas, together with the states' acknowledged lack of jurisdiction over that activity at the time Congress passed the NGA, further support the conclusion, reflected in the decisions of this Court, that FERC possesses plenary jurisdiction over such interstate transportation. Furthermore, this Court's prior decisions unambiguously instruct that state regulation, *even if nominally within a regulatory sphere reserved to the states by the NGA*, must yield to FERC's jurisdiction if such state regulation would hinder or frustrate FERC's efforts to achieve comprehensive, uniform regulation of interstate transportation.

Here, the court of appeals determined that capacity release transactions were part of an activity -- the interstate transportation of natural gas -- committed to FERC's exclusive jurisdiction by the NGA. Having so found, the court of appeals, in light of the NGA's language and purpose, as well as the prior decisions of this Court, necessarily rejected the contentions, pressed here by the petitions, that the NGA reserved regulation of capacity release transactions between LDCs and their customers, and by municipalities, to state or local authorities. To do otherwise would have opened the door to the regulation of capacity release transactions by multiple state and local regulatory bodies, thereby hindering, if not precluding, FERC's ability to regulate an aspect of interstate transportation -- the reallocation of interstate pipeline capacity -- in the comprehensive, uniform manner intended by the NGA.

Finally, the petitions do not dispute the court of appeals' determination that capacity release transactions are matters subject to FERC's NGA Section 1(b) jurisdiction over interstate transportation. Petitioners' concession on this general jurisdictional determination is fatal to their specific jurisdictional arguments about releases in specific settings. Having conceded that capacity release transactions come within

FERC's exclusive NGA jurisdiction over the interstate transportation of natural gas, Petitioners cannot then credibly argue that the statute simultaneously guarantees "the primacy of state regulation," (LDC Petition at 19) regarding the interstate transportation activities of certain entities (*i.e.*, LDCs and municipalities). Indeed, as noted earlier, the states' *complete lack* of jurisdiction over the interstate transportation of natural gas represented one of the factors necessitating passage of the NGA. If, as the PSCs contend, the NGA intended to reserve to the states "those areas which they had historically controlled," PSC Petition at 11, then Congress could not have reserved to the states the right to regulate an interstate transportation activity such as capacity release because, as the petitions concede, the Commerce Clause denied the States any authority to regulate the transportation of natural gas in interstate commerce. LDC Petition at 4; PSC Petition at 11.

III. The PSC and LDC Petitions Fail to Demonstrate That Capacity Release Transactions Fall Within the States' Jurisdiction Over "Local Distribution."

The petitions submitted by the PSCs and the LDCs make much of the "historic state authority over LDCs and intrastate customers." LDC Petition at 25. *See also* PSC Petition at 14 ("the States long have had power to regulate all aspects of the relationship between LDCs and their end-users"). The PSCs and LDCs contend that, through the jurisdiction reserved to the states by NGA Sections 1(b) and 1(c), Congress intended that states retain "a *comprehensive* scheme of rate control over LDCs." LDC Petition at 24 (emphasis in original). *See also* PSC Petition at 15 ("the state agency has the authority, and a duty, to translate that cost of service into rates that satisfy local concerns"). This comprehensive scheme of state regulation purportedly requires "consistency and exclusivity of control over LDCs' relationship with their local customers"

including the manner in which LDCs reassign their right to use interstate pipeline capacity to those customers. LDC Petition at 24. Otherwise, LDCs might release their interstate pipeline capacity exclusively to out-of-state interests, thereby denying LDC ratepayers the benefit of their "investment" in interstate pipeline capacity. LDC Petition at 27; PSC Petition at 13-14. The PSCs and LDCs characterize FERC's NGA jurisdiction as wholly derivative of and supplemental to the states' jurisdiction. *See, e.g.,* LDC Petition at 19 ("the scope of state authority should have been the touchstone for determining the scope of federal authority"); PSC Petition at 11 (NGA enacted "to fill the gaps in regulatory authority where the States were precluded from acting"). However, whether or not one agrees with the petitioners' policy quarrel with FERC, the petitioners' jurisdictional arguments are baseless.

The interpretation of NGA jurisdiction proffered by the PSCs and LDCs attempts to bootstrap state regulatory authority over rates for "local distribution" into a broader jurisdictional mandate. By framing the crux of their jurisdictional argument in malleable terms such as "the service that LDCs provide to their customers," PSC Petition at 10, and "local distribution companies' services to end-users within the state" LDC Petition at 18, they subtly seek to expand the scope of activities subject to state regulatory authority.

The release of interstate pipeline capacity by an LDC to its customer, however, is not a "service" subject to state jurisdiction for the fundamental reason that it is not a "service" that the states possess authority to regulate on their own. Recall that after issuance of Order No. 436, FERC -- not state regulatory agencies -- authorized pipelines' capacity release, capacity brokering, and capacity reassignment programs. *See supra* notes 6-8.

As the court of appeals correctly determined, capacity release requires either the *temporary or permanent abandonment* of pipeline service to one interstate pipeline customer and the corresponding *initiation of interstate transportation* service to the "replacement" shipper. Pet. App. at 80a. Both abandonment and initiation of interstate transportation service -- the core elements of a capacity release transaction -- are committed to FERC's jurisdiction by NGA Sections 1(b), and are made expressly subject to FERC's approval by NGA Sections 7(b) and 7(c), respectively. 15 U.S.C. §§ 717f(b)(c). For these reasons, plus FERC's exclusive authority over pipelines' tariffs terms and conditions, the court of appeals was correct in concluding that the states "have never regulated the terms and conditions of interstate pipeline transportation." Pet. App. at 82a.

Furthermore, even assuming for argument's sake that FERC's jurisdiction over capacity release transactions was uncertain, the consequences that flow from the state-centric jurisdictional analysis urged by the PSCs and LDCs would necessitate committing those transactions to federal jurisdiction. As this Court explained in *FPC v. Louisiana Power & Light Co*, 406 U.S. 621, 631 (1972):

> [I]n a borderline case where congressional authority is not explicit we must ask whether state authority can predictably regulate a given area and, if we find that it cannot, then we are impelled to decide that federal authority governs.

(*quoting FPC v. Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1, 19-20 (1961)). There, the Court decided that direct sales by interstate pipelines to end-users -- which are not subject to FERC rate regulation -- were subject to FERC's curtailment regulations. In addition to finding curtailment a

matter of interstate transportation, the Court concluded that "[c]omprehensive and equitable curtailment plans for gas transported in interstate commerce . . . are practically beyond the competence of state regulatory agencies." *Louisiana Power & Light*, 406 U.S. at 641. The Court reasoned that:

> the inevitable result would be varied regulatory programs of state courts and agencies, interpreting a countless number of different contracts and applying a variety of state agency rules . . . Besides, a state agency empowered to regulate these contracts would be obliged to regulate in the State, not the national interest.

Id. at 633.

Here, the PSCs and LDCs assert state jurisdictional preeminence over but one aspect of capacity release transactions: releases of interstate transportation made by LDCs to their customers. *See* PSC Petition at 13, 14; LDC Petition at 3, 24. Their petitions do not contend, for example, that releases made by LDCs to entities outside their service territories, or releases obtained by an LDC's end-user customers from an entity other than the LDC, come within a state's regulatory jurisdiction. Thus, even if accepted, the PSCs' and LDCs' jurisdictional claims would leave states without authority to "predictably regulate" all capacity release transactions. Under such circumstances, *Louisiana Power & Light* teaches that extension of state jurisdiction would be unwarranted.[14/]

[14/] This analysis applies with equal force to the municipalities' argument that their capacity release transactions -- but not other capacity release transactions -- are definitionally excluded from FERC's NGA jurisdiction and, therefore, are subject to state or local regulation.

Moreover, partial state jurisdiction over certain capacity release transactions inevitably would bring about the type of cross-cutting, self-interested state regulatory actions eschewed by the Court in *Louisiana Power & Light*. Worse still, the jurisdictional theory espoused by the PSCs and LDCs would produce simultaneous FERC/state regulation of capacity release transactions, the very kind of "overlapping control" that, according to Petitioners, Congress did not intend when it passed the NGA. LDC Petition at 18. *See also* PSC Petition at 14-16 (discussing NGA's "dual jurisdictional design"). If every state could promulgate its own regulations governing LDCs releases of interstate capacity to their own customers, a system of preferences and rates could develop that would interface with interstate transportation access and the federally approved interstate capacity release market. Indeed, the conflicting state and federal regulatory objectives described by the LDCs' petition all but ensure that the dual jurisdiction over capacity releases produced by their interpretation of the NGA would yield regulatory conflict. *See* LDC Petition at 25-28.

Finally, contrary to the PSCs' and LDCs' contentions, FERC's capacity release regulations do not infringe on the states' legitimate ratemaking jurisdiction regarding local distribution service. FERC's regulations establish the maximum rate that can be charged for interstate transportation, including in a capacity release transaction; they do not affect how costs incurred by LDCs are treated for ratemaking purposes at the state level. States' regulatory bodies remain free to allocate the costs of pipeline capacity among LDC customer classes in the manner they deem in the public interest. Equally important, state regulators can (and do) require LDCs to use revenues obtained through capacity releases to reduce the fixed costs borne by the ratepayers whose rates have

"purchased" that interstate pipeline capacity.[15/] In this way, the LDC's ratepayers benefit from its capacity release transactions. Accordingly, claims that ratepayers will lose the benefit of their "investment" in interstate pipeline capacity absent state jurisdiction over LDC capacity release transactions lack substance.

15/ *See, e.g., Re Guidelines for Further Unbundling of Natural Gas,* 148 P.U.R. 4th 441, 444 (N.J. BPU 1993)(directing that the aim of an LDC's capacity release program "should be to provide the greatest contribution to the system's fixed capacity costs, while maintaining reliability for the firm sales customers").

CONCLUSION

For the foregoing reasons, the petitions for writ of certiorari in Nos. 96-1186, 96-1187, and 96-1188 should be denied.

Respectfully submitted,

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In The

Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,

Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

BRIEF *AMICI CURIAE* OF THE AMERICAN GAS ASSOCIATION AND CITIZEN ACTION

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BRIEF *AMICI CURIAE* OF THE AMERICAN GAS ASSOCIATION AND CITIZEN ACTION

Pursuant to Rule 37.2, the American Gas Association (hereafter "A.G.A.")[1] and Citizen Action (hereafter "Citizen") respectfully submit this brief *amici curiae* in support of the petitions for writ of *certiorari* filed by petitioners Associated Gas Distributors, et al., ("AGD") the Public Service Commission for the State of New York, *et al.*, and the American Public Gas Association, *et al.*("APGA"). The written consents of the parties are attached.

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1 Public Service Company of North Carolina does not join in this brief.

INTEREST OF THE *AMICI CURIAE*

A.G.A. is a national non-profit trade association representing over 200 local distribution companies (hereafter "LDCs" or "gas distributors") principally engaged in distributing natural gas in the 50 states and the District of Columbia. A.G.A. member companies provide retail gas sales and transportation service to more than 55 million residential, commercial and industrial customers across the nation within state designated service territories.

Citizen Action is a nationwide consumer and environmental watchdog organization with over two million members in 31 states. A large percentage of Citizen Action members are residential consumers of natural gas and are concerned about the availability and price of natural gas supplies.

The question presented by AGD and the state commissions is whether the Federal Energy Regulatory Commission ("FERC" or "the Commission") has jurisdiction over LDCs' release to local retail customers of the rights LDCs have purchased to use pipeline capacity to serve local retail sales customers, even though Sections 1(b) and 1(c) of the Natural Gas Act ("NGA" or "the Act")[2] each expressly grant FERC jurisdiction only where states constitutionally cannot act. Similarly, APGA presents the question whether FERC can regulate municipalities' release of pipeline capacity despite the NGA's unequivocal exemption of municipal gas companies from FERC regulation.

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[2] 15 U.S.C. § 717 (b) & (c) (1994) (Pet. App. at 1007a - 1009a).

As national associations of local distributors and gas consumers, A.G.A. and Citizen have a particular interest in the preservation of the statutory prohibition of federal jurisdiction to regulate distribution of natural gas. The opinion of the United States Court of Appeals for the District of Columbia Circuit, affirming the Commission's authority over releases of pipeline capacity rights by LDCs to their retail sales customers, eviscerates the jurisdictional scheme codified by Congress in the NGA by undermining the authority of state regulatory agencies and municipalities to regulate effectively local natural gas distribution companies.

A.G.A. and Citizen accordingly submit this brief *amici curiae* urging the Court to issue its writ of *certiorari* to consider this matter.

SUMMARY OF ARGUMENT

FERC has extended its regulation of open access pipeline transportation to the secondary market in transportation, even under circumstances where LDCs seek to release pipeline capacity rights to their own local retail sales customers for whom they have purchased those rights. Under FERC's rules, unless releases are prearranged at the pipeline's maximum tariff rate or are for a month or less duration, releases of capacity by LDCs must be posted on an electronic bulletin board and are auctioned to the highest bidder, subject to a cap equal to the pipeline's maximum monthly tariff rate. FERC's assertion of jurisdiction over releases of capacity by LDCs to their own retail customers impedes state regulators from ensuring that the local retail customers that pay rates reflecting the full costs of the pipeline capacity in fact gain the benefit of those capacity rights.

LDCs contracted for these capacity rights to provide firm sales service to their local retail sales customers. This retail sales service is subject to the exclusive jurisdiction of the states. Because of FERC's open access pipeline transportation policy, many of these customers now are able to purchase gas from alternative suppliers, but they need to use the pipeline capacity to access alternative suppliers. LDCs and state regulators seek to enable these local retail customers to use the capacity rights the LDC purchased to serve these retail customers through direct releases, unencumbered by FERC's regulation.

FERC's rules interfere with the implementation of state energy policy. FERC's assertion of jurisdiction over capacity releases to local retail customers hampers states in devising optimal mitigation of the firm embedded cost rates paid by LDCs and passed along to firm retail customers. FERC's rules hamper states in crafting programs to enhance local customers' competitive options in the evolving competitive energy markets. The rules interfere with states' ability equitably to allocate the embedded cost of gas transportation to both electricity and gas sold in retail markets.

FERC's regulation, instead, fosters releases of capacity to marketers who often sell to large end-users located out of state. The marketers generally pay only a fraction of the embedded costs of the transportation capacity that are paid by the LDC's residential, small commercial and other firm retail sales customers for whom the capacity is reserved. Thus, the marketers and out-of-state end-users benefit from deep discounts to transportation costs that essentially are paid by the local retail sales customers. In addition, because many

of these out-of-state end-users are electric generators, FERC's rules skew retail energy markets against LDC-supplied gas that bears the full embedded costs of the pipeline's transportation service.

In regulating capacity releases by LDCs to local retail customers, FERC is treading on ground that Congress, in the Natural Gas Act, left to the states to regulate. This Court emphatically and consistently has upheld the principle that the NGA created FERC jurisdiction only over those areas of natural gas transportation and sales that states constitutionally were unable to regulate. Regulation of LDCs' release to local retail customers of transportation capacity purchased to serve those customers is a matter that, under traditional principles of NGA federalism, should be left to the states. FERC has usurped state authority and the court below erred grievously in affirming FERC's decision with respect to this issue.

FERC's rules governing capacity release suffer from the same fatal flaw as the Commission's "Special Marketing Programs" of the mid-1980's, which were remanded by panels of the D.C. Circuit including then Judges Scalia and Ginsburg, in the *Maryland Peoples Counsel v. FERC* cases.[3] The capacity release rules favor large out-of-state end-users, that are not captive to firm gas service, over residential, small commercial and other firm LDC retail customers. These rules stifle development of a robust secondary market in transportation capacity that would benefit all consumers and not just a few favored large volume end-users.

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[3] *Maryland People's Counsel v. Fed. Energy Reg. Comm'n*, 761 F.2d 768 (D.C. Cir. 1985)("MPC I"), 761 F.2d 780 (D.C. Cir. 1985)("MPC II").

ARGUMENT

THE LOWER COURT'S DECISION UNLAWFULLY ALLOWS FERC TO USURP STATE AUTHORITY TO REGULATE NATURAL GAS DISTRIBUTORS' USE OF PIPELINE CAPACITY PURCHASED TO SERVE LOCAL RETAIL CONSUMERS.

A. The Natural Gas Act Preserved the Full Scope of State Regulatory Authority Over LDCs' Activities to Serve Local Retail Consumers and Extended Federal Jurisdiction Only in Areas Where States Constitutionally Cannot Act.

The NGA, 15 U.S.C. §§ 717-717z, conferred upon the Federal Power Commission, precursor to FERC, the power to regulate certain aspects of interstate commerce in natural gas in order to protect the public interest. This Court has confirmed time and again, most recently in *General Motors Corp. v. Tracy,* that Congress intended not to occupy the entire field of its commerce clause power to regulate commerce in natural gas.[4] Rather, Congress intended to occupy only the

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[4] *See General Motors Corp. v. Tracy, Tax Comm'r of Ohio*, No. 95-1232, slip op. at 12 (U.S. Feb. 18, 1997)(stating that the Natural Gas Act left "undisturbed the recognized power of the States to regulate all in-state gas sales directly to consumers"); *Panhandle Eastern Pipe Line Co. v. Public Service Comm'n,* 332 U.S. 507, 516 (1947) (holding that the Natural Gas Act did not preempt state regulation of local direct sales by pipelines to industrial users).

portions of the field not subject to state regulation. The Act expressly provides that federal jurisdiction does not extend to "any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution . . ." 15 U.S.C. § 717(b) (Pet. App. at 1007a - 1008a). *See also* 15 U.S.C. § 717(c) (Pet. App. at 1009a). In upholding the Commission's strained expansion of the NGA, the lower court nullifies the exemption provided by the NGA and thereby allows FERC to intrude into areas Congress expressly left to local control.

LDCs historically purchased bundled service that included gas supplies and firm transportation on interstate pipelines to serve residential, commercial and other retail customers with firm energy needs. Because pipelines now transport for many suppliers, LDCs now manage portfolios of gas supplies they purchase from a variety of sources. LDCs must continue to maintain contracts with pipelines for sufficient firm transportation capacity rights to meet the needs of customers that continue to look to the LDC for reliable gas distribution service, especially on the coldest days of the year.

Under FERC-mandated pipeline rate design, LDCs pay an allocation of the full embedded costs of the pipeline capacity reserved to meet the gas supply needs of their customers. These costs in turn are recovered in the LDC's rates to its firm customers. To mitigate these costs and to enhance efficient use of pipeline capacity, LDCs seek to sell to other shippers transportation capacity rights that the LDCs do not need during any given period. When LDCs transfer these capacity rights directly to their own retail customers, the release should not be subject to FERC's encumbering capacity release program. FERC's assertion of jurisdiction over such direct transfers of capacity rights

to local retail customers precludes states from governing how the value of the capacity purchased incident to retail sales service is allocated among the retail customers that are paying to reserve that capacity. FERC's assertion of jurisdiction here has usurped states' authority to regulate the local economic issues entailed in providing reliable retail gas service.

The decision below affirmed FERC's assertion of jurisdiction over LDCs' release of transportation capacity to local retail customers. In so doing, the court failed to give effect to the full measure of state authority in the area, and instead assumed, contrary to this Court's consistent instruction, that the NGA fully occupied the potential scope of federal jurisdiction.

Petitioners have set forth why federal regulation of LDCs' and municipal utilities' management of the capacity rights they purchase to serve their local sales customers and seek to release to local retail customers exceeds the Commission's authority under the Natural Gas Act. The state commissions' petition describes how FERC's regulation impedes states' rights effectively to protect the economic interests of the captive retail consumers of natural gas. A.G.A. supports but will not repeat these arguments; instead we describe how the Commission's regulation has the perverse effect of penalizing precisely the natural gas consumers that the NGA is intended to protect.

B. Competition and Open Access Unbundled Transportation Fundamentally Have Altered Commercial Relationships in Natural Gas Markets, But NGA Jurisdiction Remains Circumscribed by State Authority to Regulate Commerce in the Interests of Local Retail Consumers.

To foster a more competitive natural gas market, Congress passed the Natural Gas Policy Act of 1978 ("NGPA") which removed "first" sales (usually by producers) of natural gas from FERC jurisdiction under the NGA.[4] A competitive spot market in natural gas developed along with a gas futures market to support it. But the wellhead market continued to remain dominated by pipeline purchasers of gas because other purchasers had no meaningful access to the pipeline transportation systems essential to reach consumers. FERC's initial "experimental increase in [natural gas] pipeline competition" was rejected as too narrow by the D.C. Circuit in the *Maryland Peoples Counsel* cases.[5] In those cases, panels led by then Judges Scalia and Ginsburg remanded FERC's "Special Marketing Programs" that had favored industrial end-users of natural gas at the expense of residential and small commercial consumers and thereby harmed rather than helped "the consumers whom the Natural Gas Act was

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[4] 15 U.S.C. §§ 3301 - 3348 (1994).

[5] 761 F.2d 768, 770 (brackets in original); *see also* 761 F.2d 780, 781 ("[t]his case features [FERC] blanket permission for interstate transportation of natural gas sold directly by producers to end users").

designed to protect." MPC II, 761 F.2d at 781 (internal quotations omitted).

In part responding to these cases, the Commission promulgated rules providing for non-discriminatory, "open access" transportation of gas by pipelines,[6] culminating in the Order No. 636 series, reviewed and remanded in part by the opinion below.[7] Briefly, Order No. 636 prohibited pipelines from selling the commodity gas bundled under a single price with the transportation service required to deliver the gas to the LDC buyer. Instead, Order No. 636 required pipelines to offer all transportation and storage services separately from the commodity, on an "open access" basis to all shippers, including those that buy gas from the pipeline (or the pipeline's marketing affiliate), under nondiscriminatory terms and conditions. The goal of requiring "open-access" transportation unbundled from the gas sale itself, the Commission said, was to "maximize the consumer benefits of the competitive

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[6] *See General Motors,* slip op at 13-14; s*ee also* Richard J. Pierce, "The Evolution of Natural Gas Regulatory Policy," Nat. Resources and Env't L.J., Summer 1995 at 53 (providing an overview of the history of natural gas regulation).

[7] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 Fed. Reg. 13267, III FERC Stats. & Regs. Preambles ¶ 30,939 (1992) ("Order No. 636") (Pet. App. at 175a - 407a); *Order on Reh'g*, 57 Fed. Reg. 36128, III FERC Stats. & Regs. ¶ 30,950 ("Order No. 636-A) (Pet. App. at 408a - 812a) *Order on Reh'g*, 57 Fed. Reg. 57911, 61 FERC ¶ 61,272 (1992) ("Order No. 636-B") (Pet. App. at 813 a - 998a); *Reh'g Denied*, 62 FERC ¶ 61,007 (1993) ("Order No. 636-C) (Pet. App. at 999a - 1000a), upheld in part and remanded in part, *United Distribution Cos. v. Federal Energy Regulatory Comm'n,* 88 F.3d 1105 (D.C. Cir. 1996) (Pet. App. at 1a - 174a); o*rder on remand*, 78 FERC ¶ 61,186 (Feb. 27, 1996).

wellhead gas market" by ensuring "that all shippers have meaningful access to the pipeline transportation grid so that willing buyers can meet in a competitive, national market to transact the most efficient deals possible."[8]

The Commission's rules requiring open access transportation and unbundling of the commodity sale from the transportation service allowed the development of a free and open wellhead market in gas commodity sales so that a multiplicity of suppliers could flourish by accessing the robust market of consumers. Now gas markets are at the next step where a robust and resilient secondary market for transportation should develop to maximize efficiency and to enable the benefits of competition to accrue directly to all consumers, not principally to large industrial or electric companies. But FERC's assertion of authority over LDC releases of capacity to local retail customers, like its "Special Marketing Programs," favors large out-of-state end-users who do not need firm LDC service and harms the residential, small commercial and other consumers that need firm supplies and pay for the reserved capacity. The capacity release regulation itself thereby undermines the goal of maximizing the consumer benefits of competition and FERC commits the same error found in the *Maryland People's Counsel* cases.

Under state regulation, LDCs also are instituting a variety of unbundled services for retail customers, enhancing the flexibility of end-users of natural gas to access directly gas being sold in competitive markets. LDCs now routinely serve retail customers that choose to purchase gas from alternative gas suppliers by assisting in arranging for pipeline transportation services

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[8] Order No. 636, 57 Fed. Reg. at 13281 (Pet. App. at 234a).

and combining those pipeline services with transportation and delivery services on an LDC's system.[9] In many states, LDCs also are offering services such as storage, balancing and standby gas sales on an unbundled basis.[10]

This Court pointed out in *General Motors*, slip op. at 24, that residential and small commercial customers still rely on transportation, distribution and sales service from LDCs bundled together to meet consumers' basic energy requirements, such as space heating.[11] This Court further emphasized that utilities have an *obligation* under state laws to serve these customers' demand. *Id.* at 17-18 & n. 10. LDCs therefore must contract for a sufficient firm daily supply of gas and pipeline delivery capacity to satisfy potential "peak day" needs of these customers, *i.e.* the higher level demand for gas service that occurs when the weather is coldest, even though average daily needs

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[9] In fact, 81 percent of gas used by industrial customers is purchased from suppliers other than their LDCs, and 25 percent of gas used by commercial customers is purchased from alternative suppliers. Dep't of Energy, Energy Info. Admin., Natural Gas Monthly, Table 24 "Percentage of Total Deliveries Represented by Onsystem Sales, by State, 1994-1995," Jan. 1997 at 64.

[10] *See generally* American Gas Association, "Gas Distribution Industry Pricing Strategies 1995 Update," (FA95-2, Dec. 1995); American Gas Association, "Providing Unbundled Services to Small Volume Customers: Issues to Consider in the Implementation Process," (IB 1996-02, January 5, 1996); American Gas Association, "Providing New Services to Residential Customers: A Summary of Pilot Programs and Unbundling Initiatives," (IB 1996-11, 11A, 11B, 1996).

[11] In addition, certain large customers, such as some apartment buildings, hospitals, industrial plants, etc. continue to prefer firm LDC service.

typically are substantially lower than the potential peak day.[12]

FERC regulates pipeline rates for firm capacity, *i.e.*, capacity that is not subject to interruption, and generally designs firm rates so that all of the fixed costs of the pipeline facilities and business during the course of the year are recovered in the charges that are prorated and paid monthly by the firm customers regardless of how much gas they require to be delivered through the capacity they have reserved. LDCs' rates recover the costs an LDC must pay a pipeline for reserved capacity along with the costs of local delivery facilities and other expenses they incur to serve their customers. State commissions actively oversee these costs to ensure that LDCs are prudent in managing their resources to provide reliable service without overpaying for gas supplies or using pipelines' transportation capacity in an uneconomic manner.[13]

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[12] In fact a typical residential load factor is only 25%; that is, on an average annual basis, residential customers take only 25% of the gas, or use only 25% of the capacity, that they require on peak and are entitled to take.

[13] *Cf. Pike County Light & Power Co. v. Pennsylvania Public Utility Comm'n*, 77 Pa. Commw. 268, 273-274, 465 A.2d 735, 737-738 (1983) (while states cannot bar regulated utilities from passing through to consumers FERC-approved wholesale rates, states properly review the prudence of LDCs' decisions to incur those costs that are avoidable or discretionary); *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 385 (1988)(Brennan, J., dissenting).

C. Including LDCs' Release of Capacity to Local Retail Customers Under FERC's Rule Results in Subsidies to Large Users and Marketers from Consumers That the NGA was Intended to Protect.

Order No. 636 permits LDCs and other holders of firm pipeline capacity to "release" pipeline capacity that currently is not being used to meet customer demand; that is, LDCs may allow third parties to use the capacity when the LDCs are not using it themselves to ship gas.[14] As defined by FERC, capacity release is the "reallocat[ion] [of] unneeded firm capacity" on a permanent or temporary basis.[15]

FERC's rules prescribe a number of cumbersome administrative procedures that not only impede LDCs' ability to use their firm rights to capacity for the benefit of their firm core customers, but also usurp states' efforts to assure the maximum benefit for the LDC customers that need and pay for the firm capacity. First, the capacity must be posted on the pipeline's Electronic Bulletin Board in a certain format and with comprehensive information. Second, the capacity must be sold to the highest bidder at a public

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[14] Order No. 636, 57 Fed. Reg. at 13824 (Pet. App. at 245a).

[15] *Id.* at 244a.

auction, subject to a rate cap equal to the pipeline's maximum approved monthly tariff rate.[16] The replacement shipper contracts directly with the pipeline, and pays the pipeline for the transportation service. The pipeline then credits the releasing LDC with the revenues from the new shipper. The LDC releasing the capacity remains obligated to the pipeline for the difference between the release price and the contract demand charge.[17]

Gas marketers won 79 percent of the capacity release awards during 1995 and that number is growing.[18] Marketers combine the released capacity with gas supplies and sell a bundled service to end-users that often are located in other states. The result is that the released capacity -- which was reserved for the use and benefit of the LDC's retail customers -- goes to other parties who do not carry the economic cost of reserving that capacity.

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16 FERC created two exceptions to the bidding process: 1) if the capacity release was prearranged at the maximum pipeline tariff rate and 2) if the capacity was released for one month or less. 18 C.F.R. §284.243(e) & (h), Order No. 636-A, 57 Fed. Reg. at 36145-46 (Pet. App. at 481a - 485a). Capacity released under these two exceptions to bidding remains subject to the Commission's rate cap. An LDC retail customer may match the highest bid and win the capacity but this is no remedy to the interference by misplaced federal regulation in state programs to enhance competitive purchase opportunities and efficient capacity allocations in local retail markets.

17 Order No. 636, 57 Fed. Reg. at 13284 (Pet. App. at 246a).

18 *See* Interstate Natural Gas Association of America, "Gas Transportation Through 1995," Issue Analysis, Rept. No. 96-3, Sept. 1996 at 8.

The economic harm to the retail customers caused by FERC's rule does not stop there. During most of the year, including the transition months of Spring and Fall, the average rates for released capacity are significantly below the maximum interstate pipeline tariff rates, and therefore significantly below a ratable share of the cost of providing the transportation service. Over the entire 1995-96 winter heating season, which was colder than normal, rates for released capacity nonetheless were discounted an average of 65 percent below maximum tariff rates.[19] During the non-heating season, April through October, capacity release rates were discounted 83 percent.[20] The economic benefit of these deep discounts often goes to the out-of-state dual fuel large users of natural gas or to the marketers serving them, depending upon market conditions.

FERC's rule perpetrates further economic harm to the retail customers who reserve and pay for firm capacity. During the coldest days of the winter, the market value of the released capacity may exceed the maximum approved tariff rate of the pipeline. FERC's monthly rate cap, however, precludes LDCs from recovering the true market value of the capacity to the detriment of the retail customers. The market value of pipeline capacity can be derived from comparing the price of gas in the production area with the price of gas at a particular city gate in markets that are distant from production. For example, in December 1996, the average spot price for gas purchased in Louisiana, a

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19 Dep't of Energy, Energy Info. Admin., *Natural Gas 1996: Issues and Trends*, December 1996, at 46-47.

20 *Id.*

major supply area, was $3.84 per MMBtu while the average spot price for gas purchased at the New York city gate was $5.22 per MMBtu.[21] The $1.38 difference between the purchase price in Louisiana and the purchase price in New York includes approximately $.24 associated with fuel, and other add-ons that are not part of the value of the transportation. Subtracting these costs leaves $1.14 as the value of the transportation from Louisiana to New York.

Under FERC's rules, however, LDCs may charge no more than the pipeline's maximum tariff rate for released capacity. A typical maximum transportation rate on a major interstate pipeline that extends from Louisiana to New York City is approximately $.31 per MMBtu. Thus the mitigation of the embedded costs paid by the LDCs' sales customers was limited to $.31, while the marketer was able to net an additional $.83 per MMBtu.

Under state law, state regulators are charged with protecting the public interest in energy services at reasonable prices. These matters clearly encompass allocating the value of capacity rights purchased by retail customers -- without interference by FERC regulation. Had FERC not usurped state regulation of capacity reserved for retail sales, the $.83 difference between the maximum tariff rate and the true value of the capacity rights would have been available to mitigate the cost to the in-state customers who paid for the capacity year round if the state so elected. The state could have elected to impose an *annual* revenue cap for released capacity equal to the pipeline's annualized embedded cost rate. State energy policy should govern

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21 Brent Friedenberg Assocs., Ltd., *U.S. Northeast Natural Gas Market Review*, December 1996, Table C1, at 28.

allocation of the economic benefit, as well as the capacity itself, that was reserved for local retail sales is resold to local retail customers.

A significant percentage of the out-of-state, large dual-fuel users of released capacity are electric generators. Thus FERC's rule results in subsidies from LDC firm gas sales customers to electric generators. A federal regulation that indirectly requires local gas consumers to subsidize costs of generating electricity wreaks havoc with state efforts to avoid cross subsidies among fuels and is a serious encroachment into the state regulatory domain of integrated resource planning. Moreover, to the extent electric generators using released capacity pay below embedded costs for transportation, LDCs are disadvantaged in competing in retail energy markets because retail gas rates must reflect the share of pipeline embedded costs that electric generators are not paying.

D. States Constitutionally Can Regulate Unbundled Retail Transportation Services and the NGA Left That Authority Undisturbed.

This Court emphatically has defended the breadth of states' authority to regulate public utilities' service to local retail customers against efforts to read the Natural Gas Act as diminishing that authority. Paraphrasing *Panhandle*, 332 U.S. 507, the Court in *General Motors* said:

> Congress's purpose in enacting the NGA was to fill the regulatory void. . . the NGA "was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any

> way [T]he scheme was one of cooperative action between federal and state agencies. . . and Congress' action . . . was an unequivocal recognition of the vital interests of the states and their people, consumers and industry alike, in the regulation of rates and service." [Citations omitted.]

General Motors, slip op. at 12 (quoting *Panhandle v. Public Service Comm'n,* 370 U.S. at 519-522).

Historically, LDCs' use of pipeline capacity incident to serving their local retail customers has been subject to strict oversight by state regulatory agencies. The sale by LDCs of transportation capacity rights, separate from the sale of natural gas itself, at the retail level does not change the local nature of the overall transaction -- natural gas service to consumers. Local retail gas service involves issues of critical importance to states, such as adequate supplies and reliable delivery capacity so that consumers are not cut off in cold weather, as well as impacts on the local economy. Congress in the NGA has left those issues to the states and the Court below erred in affirming FERC's preemption of state authority.

LDCs should be permitted to release capacity to customers behind the city gate under terms regulated by the states for the benefit of those customers on behalf of which the LDC reserved the firm capacity and is paying the full embedded costs. Congress in the NGA left to state regulation that which the constitution permits states to regulate. The disposition of rights to move gas to local end-user markets is an area of local concern constitutionally within the states' purview.

CONCLUSION

For the reasons stated, A.G.A. and Citizen urge the Court to grant the petitions for a writ of *certiorari* to the D.C. Circuit in Nos. 96-1186, 96-1187, and 96-1188.

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Nos. 96-1186, 96-1187, 96-1188 and 96-1189

In the Supreme Court of the United States

OCTOBER TERM, 1996

ASSOCIATED GAS DISTRIBUTORS, ET AL., PETITIONERS
v.
FEDERAL ENERGY REGULATORY COMMISSION

AMERICAN PUBLIC GAS ASSOCIATION AND CITIZENS GAS & COKE UTILITY, PETITIONERS
v.
FEDERAL ENERGY REGULATORY COMMISSION

NEW YORK PUBLIC SERVICE COMMISSION, ET AL., PETITIONER
v.
FEDERAL ENERGY REGULATORY COMMISSION AND UNITED STATES OF AMERICA

BURLINGTON RESOURCES OIL & GAS COMPANY, PETITIONER
v.
FEDERAL ENERGY REGULATORY COMMISSION

ON PETITIONS FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

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QUESTIONS PRESENTED

Order No. 636 of the Federal Energy Regulatory Commission (FERC) requires the unbundling of interstate natural gas transportation service from sales service in order to facilitate competition in the national market for gas at the wellhead and ensure equal access to transportation services. The questions presented are:

1. Whether FERC's jurisdiction over interstate transportation of natural gas under the Natural Gas Act, 15 U.S.C. 717 *et seq.*, supports application to local natural gas distribution companies and municipally owned natural gas companies of FERC regulations governing transfer of rights to capacity on interstate natural gas pipelines.

2. Whether FERC correctly concluded that, pursuant to its program for reallocation of pipeline capacity under long-term transportation contracts, it could not require natural gas pipelines to accept bids lower than the maximum just and reasonable rate for transportation capacity.

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Section 284.221(d) 6-7
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Robert Crandall & Jerry Ellig, *Economic Deregulation and Customer Choice: Lessions for the Electric Industry* (1997) 9
H.R. Rep. No. 709, 75th Cong., 1st Sess. (1937) 13
Howard R. Williams, *Manual of Oil & Gas Terms* (8th ed. 1991) 7

In the Supreme Court of the United States

OCTOBER TERM, 1996

No. 96-1186

ASSOCIATED GAS DISTRIBUTORS, ET AL., PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION

No. 96-1187

AMERICAN PUBLIC GAS ASSOCIATION AND CITIZENS GAS AND COKE UTILITY, PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION

No. 96-1188

NEW YORK PUBLIC SERVICE COMMISSION, ET AL., PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION AND UNITED STATES OF AMERICA

No. 96-1189

BURLINGTON RESOURCES OIL & GAS COMPANY, PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION

ON PETITION FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

OPINIONS BELOW

The opinion of the court of appeals (Pet. App. 1a-174a)[1] is reported at 88 F.3d 1105. The orders of the Commission are reported in Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Pt. 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939 (Pet. App. 175a-407a), order on reh'g, Order No. 636-A, F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950 (Pet. App. 408a-812a), order on reh'g, Order No. 636-B, 61 F.E.R.C. (CCH) ¶ 61,272 (Pet. App. 813a-998a), reh'g denied, 62 F.E.R.C. (CCH) ¶ 61,007 (Pet. App. 999a-1000a) (Order No. 636).

JURISDICTION

The judgment of the court of appeals was entered on July 16, 1996. A petition for rehearing was denied on October 29, 1996. Pet. App. 1003a-1004a. The petitions for a writ of certiorari were filed on January 27, 1997. The jurisdiction of this Court is invoked under 28 U.S.C. 1254(1).

STATEMENT

1. In the rule at issue here, Order No. 636, the Federal Energy Regulatory Commission (FERC or Commission) completed the natural gas deregulatory program it had initiated almost a decade earlier. Order No. 636 mandates the "unbundling" of interstate natural gas sales service from transportation service, requiring that those services be sold separately to

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[1] All references to "Pet. App." are to the appendix to the petition in No. 96-1186.

natural gas purchasers. FERC adopted its mandatory unbundling policy in order to "improve the competitive structure of the natural gas industry to facilitate the operation of a national wellhead market as envisioned by Congress," Pet. App. 229a; to "ensure equality of transportation service between gas sold by pipelines or their affiliates and gas sold by other sellers," *id.* at 234a; and, ultimately, to "provide natural gas consumers with access to an adequate supply of clean and abundant natural gas at reasonable prices," *id.* at 229a. Order No. 636 imposes "capacity-release" requirements that allow holders of firm transportation rights on interstate pipelines to resell those rights under uniform terms. *Id.* at 244a-252a.[2] The order also imposes right-of-first refusal (ROFR) requirements, which allow existing shippers with long-term transportation contracts to retain their rights to pipeline capacity if they agree to match the highest bid for that service from alternative purchasers, up to the maximum cost-based transportation rate for the service approved by the Commission under the Natural Gas Act (NGA), 15 U.S.C. 717 *et seq.* Pet. App. 671a-692a.

2. In 1985, FERC initiated a deregulatory program designed to encourage the voluntary unbundling of pipeline gas sales from pipeline transportation services. Whereas pipelines had traditionally bought gas at the wellhead and transported it before turning it over to the purchaser, the Commission dramatically

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[2] Transportation is referred to as "firm" when delivery is guaranteed without interruption, as distinguished from "interruptible" transportation, which may be interrupted to accommodate the requirements of firm shippers. See Pet. App. 11a n.10.

changed the natural gas industry by enabling pipelines to offer gas sales and transportation services separately, thereby affording customers the opportunity to purchase gas from one company and hire a separate company's pipeline to transport it. See Pet. App. 10a-15a (discussing background to Order No. 636). To further enhance the efficiency of the natural gas market, the Commission encouraged pipeline customers, through a variety of mechanisms, to sell or release their unwanted firm transportation capacity to other shippers.

The partial unbundling of sales and transportation service that resulted from the voluntary program presented serious inefficiencies in allocation of unused transportation capacity. For example, because bundled firm service had often provided superior reliability, many customers continued to pay reservation fees to retain that service, while in most instances using cheaper interruptible service to transport their wellhead gas. See Pet. App. 15a-16a. The secondary transportation market that resulted from partial unbundling produced such a wide variety of capacity-reallocation arrangements that it became impossible for FERC to monitor those programs adequately in order to "ensure that all allocations are nondiscriminatory"; there were "simply too many potential assignors of capacity" for FERC to assure that capacity was allocated "in a manner consistent with the public convenience and necessity." *Algonquin Gas Transmission Co.*, 59 F.E.R.C. (CCH) ¶ 61,032, at 61,095 (Apr. 8, 1992), reh'g denied, 60 F.E.R.C. (CCH) ¶ 61,113 (Aug. 3, 1992).[3] Accordingly, the Commission

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[3] In the *Algonquin* orders, which were issued as companion orders to Order No. 636, the Commission revoked the certifi-

found that the continued operation of the voluntary capacity reallocation programs it had previously approved "would frustrate the goal of * * * remedy[ing] an unreasonable restraint of trade" and would therefore be "unjust and unreasonable and contrary to the public interest." 59 F.E.R.C. (CCH) ¶ 61,032, at 61,096-61,097.

3. To address the problems that arose from partial, voluntary unbundling, FERC's Order No. 636 mandates the complete unbundling of pipeline sales from transportation service and institutes a number of requirements to achieve a fair and open market for transportation rights, and to prevent undue discrimination. See Pet. App. 15a-18a (summarizing Order No. 636).

FERC established, *inter alia*, a uniform capacity-release rule to ensure that unneeded transportation capacity on interstate pipelines is allocated fairly and efficiently. See Pet. App. 71a-103a, as amended by Pet. App. 1001a-1002a, 244a-252a.[4] Under FERC's rule, any shipper desiring to release firm capacity must notify the affected interstate pipeline. The pipeline must then post the available capacity, along with applicable conditions, on an electronic bulletin board for a reasonable period of time, and assign the capacity to the shipper making the best offer for the capacity, up to the maximum just and reasonable price established by the Commission. *Id.* at 245a-247a. A

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cates of public convenience and necessity it had previously issued for capacity reallocation programs and required instead that pipelines abide by the uniform capacity reallocation program of Order No. 636. Review of those orders was consolidated with review of Order No. 636. Pet. App. 19a & n.20.

[4] FERC's capacity-release rule is codified at 18 C.F.R. 284.243.

shipper releasing firm capacity transportation rights may designate a specific party to receive those rights, but the pipeline must post such a prearrangement on the electronic bulletin board, and the designated party can receive the transfer only if no other party makes a better offer. *Id.* at 244a-247a. If the designated shipper bids at the ceiling rate, however, it automatically receives the transportation rights. *Id.* at 245a.

In addition, FERC recognized that, if the wellhead market for natural gas is to function effectively, transportation should be made equally available to all gas purchasers, regardless of whether the wellhead merchant is affiliated with the pipeline. Pet. App. 234a-235a. The principle of "transportation equality" protects captive customers—*i.e.* those connected to only one pipeline, who typically have long-term contracts—from the pipeline's market power. To implement that principle, Order No. 636 imposes, *inter alia*, a "right-of-first-refusal" (ROFR) process allowing competitive allocation of capacity at the expiration of long-term contracts for pipeline transportation, while protecting customers with expiring contracts who remain dependent upon continued transportation service. See *id.* at 43a-56a.

As a condition of granting pipelines authority, under Section 7(b) of the NGA, 15 U.S.C. 717f(b), to abandon contracts at the end of their terms, FERC required pipelines to institute a ROFR mechanism inviting renewal of any long-term contract if the existing shipper matches the highest offer (up to a maximum just and reasonable rate) from any competing bidder for the transportation capacity. 18 C.F.R.

284.221(d); Pet. App. 668a-673a.[5] FERC reasoned that, in general, "a pipeline's service obligation * * * should be determined, in the first instance, by the contract negotiated by the parties," *id.* at 312a, and pipeline transportation capacity is most efficiently allocated if it is sold to those willing to pay the highest price for the capacity, *id.* at 675a. The Commission recognized, however, that where contracts for longer than one year are involved, existing customers may rely on continued service and require some assurance that their current long-term contracts can be extended.

The Commission concluded that the ROFR mechanism "strikes the appropriate balance between the needs of customers for continued service and the benefits of competition in establishing the terms of service." Pet. App. 325a.

4. The court of appeals upheld in large part FERC's Order No. 636, remanding only issues not relevant here. The court concluded that FERC's plenary jurisdiction over interstate transportation of gas on interstate pipelines gives it the authority to regulate the exchange of interstate transportation capacity. Pet. App. 71a-94a. Uniform capacity-release requirements "operate as a term or condition of pipeline service" that FERC may apply to all parties engaged in such interstate transactions, including parties that otherwise are exempt from FERC jurisdiction as local distribution companies (LDCs)

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[5] A pipeline must also extend a contract if it contains either an evergreen or a rollover clause. Such clauses allow parties to extend their contract for a specified term upon the contract's expiration. See Howard R. Williams, *Manual of Oil & Gas Terms* 406-407, 1083-1084 (8th ed. 1991).

or municipally-owned natural gas distributors (municipals). *Id.* at 80a. The court rejected petitioners' asserted distinction between "rights to" and "rendition of" service, concluding that, "[w]hile the pipeline provides *transportation* only when a party utilizes capacity rights to transport gas, the pipeline provides *transportation services* throughout the capacity release process." *Ibid.* (emphasis in original).

The court also rejected several challenges to the ROFR mechanism. Pet. App. 43a-56a.[6] The court upheld the Commission's conclusion that it could not require pipelines considering existing customers' bids under the ROFR mechanism to accept rates below the maximum just and reasonable rate. *Id.* at 53a-56a. The court also concluded that the Commission had included adequate safeguards in Order No. 636 against pipeline manipulation of bids, that there was no basis upon which to require pipelines to accept bids at less than the approved rate, and that the Commission had provided proper incentives in the ROFR process to encourage pipelines to accept discounted rates. *Ibid.*

ARGUMENT

Petitioners challenge the court of appeals' decision upholding the capacity-release and ROFR requirements of Order No. 636. That decision is consistent with the well established principle that the NGA

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[6] Although the court generally affirmed the Commission's ROFR mechanism, it remanded for further consideration the requirement that, in order to retain their existing pipeline capacity, existing shippers must match bids for terms of up to 20 years duration. Pet. App. 49a-53a. On remand, the Commission shortened the maximum term to five years. Order No. 636-C, 78 F.E.R.C. (CCH) ¶ 61,186 (Feb. 27, 1997).

granted FERC "exclusive jurisdiction 'over the sale and transportation of natural gas in interstate commerce,'" *Northwest Cent. Pipeline Corp.* v. *State Corp. Comm'n*, 489 U.S. 493, 510 (1989), and with the decisions of this and other courts construing that grant of jurisdiction. Further review is not warranted.[7]

1. Petitioners Associated Gas Distributors, et al. (AGD) (No. 96-1186), the New York Public Service Commission, et al. (NYPSC) (No. 96-1188) and the American Public Gas Association, et. al. (APGA) (No. 96-1187) challenge the court's affirmance of the capacity-release requirements in Order No. 636. The court of appeals correctly concluded that FERC's capacity-release program is a legitimate exercise of its plenary jurisdiction under the NGA to regulate the transportation of gas in interstate commerce.

a. There is no merit to petitioners' contentions (96-1186 Pet. 18-24; 96-1188 Pet. 13-16) that the Com-

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[7] Order No. 636 comports with FERC's obligation under the NGA to ensure consumers a supply of gas "at the lowest possible reasonable rate." *Atlantic Ref. Co.* v. *Public Serv. Comm'n*, 360 U.S. 378, 388 (1959). As recent studies demonstrate, consumers have reaped substantial benefits from the Commission's decade-long restructuring of the natural gas industry, of which Order No. 636 represents the "latest step." Pet. App. 6a. Specifically, adjusted for inflation, prices paid by local utilities for gas at the "city gate" dropped by 52% in the last decade, prices paid by residential and commercial customers dropped 32% and 38%, respectively, and prices paid by industrial and electric utility customers fell by approximately 60%. Those figures demonstrate that "open access has placed strong pressures on interstate pipelines to reduce their costs and pass the savings through to their customers." Robert Crandall & Jerry Ellig, *Economic Deregulation and Customer Choice: Lessons for the Electric Industry* 10-11 (1997).

mission lacks jurisdiction to apply its capacity-release rules to capacity on interstate pipelines held by LDCs. As the court of appeals concluded, "FERC's capacity release program is a legitimate exercise of its jurisdiction over the interstate transportation of natural gas." Pet. App. 77a. Section 1(b) of the NGA grants the Commission jurisdiction over three distinct aspects of the natural gas industry: (1) "the transportation of natural gas in interstate commerce," (2) "the sale in interstate commerce of natural gas for resale for ultimate public consumption," and (3) "natural-gas companies engaged in such transportation or sale." 15 U.S.C. 717(b); see *FPC* v. *Louisiana Power & Light Co.*, 406 U.S. 621, 636 (1972) (*LP&L*). As this Court has emphasized, the Commission's transportation jurisdiction is "plenary" and extends to all transactions "except those which Congress has made explicitly subject to regulation by the States." *FPC* v. *Southern California Edison Co.*, 376 U.S. 205, 216 (1964). Further, as this Court has repeatedly stressed, the Commission's power extends to regulating transactions that, if left unregulated, could interfere with the achievement of the goals of the NGA. *Schneidewind* v. *ANR Pipeline Co.*, 485 U.S. 293, 310 (1988); *Transcontinental Gas Pipe Line Corp.* v. *State Oil & Gas Bd. of Mississippi*, 474 U.S. 409, 423-424 (1986); *United Gas Pipe Line Co.* v. *McCombs*, 442 U.S. 529, 538 (1979).

The court of appeals' conclusion that the uniform capacity-release requirements are an appropriate exercise of FERC's jurisdiction over interstate transportation of natural gas (Pet. App. 79a-86a) follows naturally from this Court's rulings that the Commission's transportation jurisdiction extends to, for example, the end-use of the transported gas, see *FPC*

v. *Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1, 7-8, 22 (1961), interruption of interstate transportation service, see *Panhandle Eastern Pipe Line Co.* v. *FPC*, 332 U.S. 507, 523 (1947), curtailment of gas sales, see *LP&L*, 406 U.S. at 641, financing of interstate pipelines, see *Schneidewind*, 485 U.S. at 306, and gas storage, see *id.* at 295 n.1. The court of appeals' decision is consistent with the decisions of all the other circuits that have addressed challenges to FERC's exercise of its transportation jurisdiction.[8]

Moreover, the court of appeals correctly noted that, "[a]s an entirely separate matter," FERC's jurisdiction over abandonments of service supports its regulation of capacity-release transactions because, "[i]n effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper." Pet. App. 80a. Under Section 7(b) and (c) of the NGA, neither abandonment nor ren-

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[8] Other circuits have unanimously held that FERC's jurisdiction extends broadly to all aspects of transportation, including the "initiation, curtailment, quality, quantity, and termination" of gas deliveries. *National Ass'n of Regulatory Util. Comm'rs* v. *FERC*, 823 F.2d 1377, 1385 (10th Cir. 1987). See, *e.g.*, *United Gas Pipe Line Co.* v. *FERC*, 824 F.2d 417, 425 (5th Cir. 1987) (limiting liability for curtailments); *Fort Pierce Util. Auth.* v. *FPC*, 526 F.2d 993, 996-998 (5th Cir. 1976) (curtailment of retail gas sales); *Corning Glass Works* v. *FERC*, 675 F.2d 392, 394-396 (D.C. Cir. 1982) (spreading of costs of liquified natural gas plant built by LDC to service customers within its territory); *Mississippi Pub. Serv. Comm'n* v. *FPC*, 522 F.2d 1345, 1350 (5th Cir. 1975) (compensating end users for losses caused by curtailments), cert. denied, 429 U.S. 870 (1976); *Panhandle E. Pipe Line Co.* v. *FPC*, 232 F.2d 467, 472 (3d Cir.) (control over the functioning of a pipeline's facilities), cert. denied, 352 U.S. 891 (1956).

dition of new service may occur without permission and prior approval of the Commission. 15 U.S.C. 717f(b) and (c).[9]

b. Petitioners incorrectly assert (96-1186 Pet. 18-21; 96-1188 Pet. 14-16) that regulation of LDCs' assignment of transportation capacity rights to gas consumers operating within the LDCs' service areas is tantamount to regulation of local distribution. Capacity-release involves assignment of rights to use firm interstate transportation capacity on high-pressure trunk lines. Those lines are not "local distribution facilities" within the meaning of Section 1(b) of the NGA. See *FPC* v. *East Ohio Gas Co.*, 338 U.S. 464, 470 (1950). FERC has not in Order No. 636 asserted jurisdiction over any activity occurring behind the city gate after the LDC has received gas from an interstate pipeline. Capacity release does not solely affect LDC capacity assignments to end-users located in local service areas, but enables all firm capacity holders, including LDCs, end-users, and marketers, to deliver gas to any existing, out-of-state delivery point on the interstate pipeline upstream of its city gate or usual delivery point. See Pet. App. 271a, 555a. Deliveries of gas to those out-of-state locations under assigned capacity rights cannot be deemed local distribution of gas, nor can any State

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[9] Petitioner NYPSC asserts (96-1188 Pet. 16), without authority, that the court of appeals erred in concluding that the Commission could regulate partial abandonments of service under Section 7 of the NGA. Petitioner's argument that partial abandonments cannot be regulated would create a serious gap in the Commission's regulatory powers and, in any event, ignores the plain requirement of Section 7(b) that a pipeline may not abandon "*any* service," 15 U.S.C. 717f(b) (emphasis added), without Commission approval.

regulate those out-of-state capacity assignments. See *Mississippi River Transmission Corp.* v. *FERC*, 969 F.2d 1215, 1218 (D.C. Cir. 1992); *Michigan Consol. Gas Co.* v. *FERC*, 883 F.2d 117, 121 (D.C. Cir. 1989), cert. denied, 494 U.S. 1079 (1990).

Even where an LDC assigns its firm capacity on an interstate pipeline to a local end-user, settled precedent makes clear that such a transaction does not constitute local distribution of gas. Indeed, the "local distribution" exception to FERC transportation jurisdiction is "confined to [an LDC's] parcelling out function and (probably) even more narrowly, to parcelling out *accompanied by* retail sales." *Public Utils. Comm'n* v. *FERC*, 900 F.2d 269, 276 (D.C. Cir. 1990). Thus, contrary to petitioners' assertions (96-1186 Pet. 16; 96-1188 Pet. 19-20), the court of appeals' application here of Section 1(b)'s established construction is consistent with the holdings of this Court, *e.g.*, *LP&L*, 406 U.S. at 637-638; *East Ohio*, 338 U.S. at 469-470, and other courts of appeals, *Cascade Natural Gas Corp.* v. *FERC*, 955 F.2d 1412, 1418 (10th Cir. 1992); *United Gas Pipe Line Co.* v. *FERC*, 824 F.2d 417, 425 (5th Cir. 1987), and plainly expressed congressional intent, H.R. Rep. No. 709, 75th Cong., 1st Sess. 3 (1937) ("local distribution * * * is made only to consumers *in connection with sales*" (emphasis added; internal quotation marks omitted)).

c. Petitioner AGD incorrectly asserts (96-1186 Pet. 21-24) that FERC has used unbundling to interfere with matters that are traditionally controlled by the States. Petitioner ignores the pivotal fact that States have never regulated the terms and conditions of interstate pipeline transportation. As the District of Columbia Circuit explained in *Public Utils. Comm'n*, 900 F.2d at 276-277:

> In an era when transporters almost invariably bought gas at one end of the pipeline and sold it at the other, gas would normally reach an end user only after a pipeline's retail sale to that user, a transaction unquestionably under the state's control, or after conventional distribution and sale by a local distributor, again clearly subject to state control. * * * Under modern conditions, by contrast, where the end user often owns the gas and uses the pipeline solely for transportation, application of *East Ohio* removes this fulcrum for state power.

See *East Ohio*, 338 U.S. at 469-470; *Cascade Natural*, 955 F.2d at 1421.

Petitioners' contentions (96-1186 Pet. 24-28; 96-1188 Pet. 13-14) that capacity release interferes with state regulation of the LDCs' traditional role as local supplier of natural gas are similarly unfounded. An LDC's use of the capacity-release program is voluntary and is aimed at unused (and presumably unneeded) capacity. See Pet. App. 244a-245a. FERC does not regulate any aspect of the rates for an LDC's retail sale of its system supply or the use of its own facilities; it regulates only the LDC's use of interstate transportation capacity. As the court of appeals observed, Section 1(b) "does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas." Pet. App. 82a.

Contrary to NYPSC's assertions (96-1188 Pet. 13-14), the uniform capacity-release mechanism is not unfair to end-users who have "paid" for LDC "pipeline capacity" through "state-approved rates." Under Order No. 636, an LDC's customer can guarantee assignment of the LDC's interstate capacity rights by

contracting with the LDC at the FERC-approved, cost-based transportation rate, or at any lower rate that trumps competing offers. Pet. App. 485a. By allowing LDCs to shed unused capacity and thereby lower costs, the capacity-release mechanism benefits consumers.

AGD incorrectly contends (96-1186 Pet. 27-28) that the capacity-release program impairs state efforts to require LDCs to unbundle local transportation service from retail sales. Rather than imposing obstacles, however, FERC's rule facilitates local unbundling by guaranteeing end-users access not only to their own LDCs' released capacity, but also to the capacity released by any other capacity holder who holds rights to a delivery point at or downstream of the LDC's position on the interstate pipeline. See Pet. App. 271a-272a, 495a-497a.[10]

d. AGD also errs in asserting (96-1186 Pet. 14-18) that the Hinshaw Amendment to the NGA, Pub. L. No. 323, 68 Stat. 36, exempts LDCs from the uniform capacity reallocation mechanism. The Hinshaw Amendment exempts from FERC regulation any person engaged in the transportation or sale in inter-

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[10] AGD argues (96-1186 Pet. 27) that Order No. 636 interferes with "blended" capacity programs now being offered by the States. That argument was neither raised before nor addressed by the Commission or the court of appeals, and there is no factual basis in the record to support it. That claim therefore is not properly presented to this Court. See 15 U.S.C. 717r(b) ("No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing."); see also *Sullivan* v. *Louisiana*, 508 U.S. 275, 279 n.1 (1993) (stating that this Court does not ordinarily review issues not raised below).

state commerce of natural gas received "within or at the boundary of a State" and "ultimately consumed within such State." 15 U.S.C. 717(c). Congress enacted the Hinshaw Amendment "to preserve state control over local distributors who purchase gas from interstate pipelines * * * [but] Congress did not intend the amendment to relieve the Commission of jurisdiction over * * * integrated interstate systems." *Louisiana Power & Light Co.* v. *FPC*, 483 F.2d 623, 633 (5th Cir. 1973), cert. denied, 416 U.S. 974 (1974). As the court of appeals explained, "the Commission's authority to regulate capacity release arises from its jurisdiction over the interstate pipeline that consummates the transaction and the subject of the transaction, the interstate transportation of gas, entirely independent of its jurisdiction over the releasing or replacement shippers." Pet. App. 82a n.62. Moreover, in order for the Hinshaw Amendment to apply, the service at issue would have to be subject to effective state regulation. The States cannot effectively regulate the transactions at issue here because they cannot prevent interstate pipelines from discriminating in favor of in-state users at the expense of out-of-state users. The Hinshaw Amendment accordingly has no application to the interstate transactions at issue here.

AGD places great weight on its contention (96-1186 Pet. 17) that the Hinshaw Amendment overruled this Court's decision in *East Ohio*, 338 U.S. at 461. Although *East Ohio*'s holding—that FERC had jurisdiction over an interstate gas pipeline operating in only one State—is no longer the law, the Hinshaw Amendment did not affect the Court's analysis in *East Ohio* of the scope of the Commission's jurisdiction over pipelines that transport gas across state lines. See

Altamont Gas Transmission Co. v. *FERC*, 92 F.3d 1239, 1246 (D.C. Cir. 1996), petition for certiorari pending, No. 96-1179 (filed Feb. 11, 1997); *Public Utils. Comm'n*, 900 F.2d at 275 n.4. Notwithstanding the particular change brought about by the Hinshaw Amendment, this Court and the courts of appeals have continued consistently to rely on *East Ohio* as a correct and otherwise still valid interpretation of the NGA. *E.g.*, *LP&L*, 406 U.S. at 636-637 & n.13; *California* v. *Lo-Vaca Gathering Co.*, 379 U.S. 366, 369 (1965); *Cascade Natural*, 955 F.2d at 1416-1421; *Public Utils. Comm'n*, 900 F.2d at 275.

e. APGA similarly contends (96-1187 Pet. 9-11) that the court of appeals erred in concluding that municipally owned gas companies must comply with the uniform capacity reallocation mechanism when they seek to reassign interstate pipeline capacity. APGA reasons that, because Section 2 of the NGA excludes municipals from the definition of "persons" regulated as "natural gas companies" under the Act, 15 U.S.C. 717a(1)-(3) and (6), FERC may not require that they comply with the terms of FERC's capacity-release program. 96-1187 Pet. 7-8. The court of appeals correctly concluded, however, that "FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations" because "FERC's transportation jurisdiction extends as a separate matter over capacity release * * * entirely independent of the jurisdictional nature of the releasing and replacement shippers." Pet. App. 84a-85a.

Although FERC lacks jurisdiction to regulate municipals as such, the Commission's jurisdiction over interstate transportation is not limited to natural-gas companies or "persons" engaged in transportation.

Instead, it extends to all interstate transportation of gas, regardless of the parties involved in such transportation. This Court has rejected the contention "that the word 'transportation' in § 1(b) must be construed as applying only to companies engaged in the business of transporting gas in interstate commerce," concluding that "the Act's language did not express any such limitation." *East Ohio*, 338 U.S. at 468. Indeed, the courts have long recognized that municipalities, although not "natural-gas companies" or "persons" under the Act, are nonetheless subject to NGA regulation under those NGA provisions that are not exclusively directed at "natural-gas companies." See, *e.g.*, *California* v. *Southland Royalty Co.*, 436 U.S. 519, 528 (1978); *Public Serv. Co.* v. *FERC*, 587 F.2d 716, 719 (D.C. Cir. 1979). Thus, as the court of appeals observed (Pet. App. 85a), this Court has concluded that the Commission may properly regulate the curtailments of both gas supply and capacity to municipals under its transportation jurisdiction, see *Transcontinental Gas*, 365 U.S. at 20-22; *LP&L*, 406 U.S. at 640—a situation involving allocation of transportation capacity among shippers in compliance with federal mandates that is "strikingly similar" to capacity release. Pet. App. 85a.[11]

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[11] APGA argues (96-1188 Pet. 13-14) that there is a distinction between transactions in the primary and secondary market for pipeline capacity. As we have noted, pages 10-11, *supra*, however, the Commission's jurisdiction over transportation extends to all aspects of interstate pipeline operation. Further, to declare such secondary transactions beyond the Commission's jurisdiction would create an anomalous gap in the comprehensive regulation intended by Congress in enacting the NGA. See *LP&L*, 406 U.S. at 631-632.

APGA further contends (96-1187 Pet. 12-19) that FERC's regulation of municipalities under its transportation jurisdiction conflicts with FERC's own policy established in *Texas Eastern Transmission Corp.*, 51 F.E.R.C. (CCH) ¶ 61,170 (May 11, 1990). The court of appeals correctly rejected that contention. Pet. App. 84a & n.64. In *Texas Eastern*, the Commission authorized firm transportation customers of an interstate pipeline to broker capacity to third parties without the involvement of the carrying pipeline itself. The Commission required such customers to obtain "limited jurisdiction" certificates under Section 7(c) of the NGA because, as brokers, they were within the meaning of NGA Section 1(b). The Commission, however, ruled that municipals were exempt transporting gas from any such certification requirement because they were not "natural gas companies" and therefore not subject to Section 7. See 48 F.E.R.C. (CCH) ¶ 61,248, at 61,873-61,875 (Aug. 22, 1989); 51 F.E.R.C. (CCH) ¶ 61,170, at 61,453-61,454. The capacity brokering arrangements in *Texas Eastern* were performed by capacity holders themselves without pipeline involvement; under Order No. 636, in contrast, FERC regulates capacity assignment by pipelines. The court of appeals thus correctly held that the *Texas Eastern* approach is inapplicable, and that FERC may require municipals' compliance with capacity-release rules as it may require their compliance with other pipeline terms or conditions of interstate transportation service. Pet. App. 84a-85a.[12]

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[12] *Texas Gas Transmission Corp.*, 55 F.E.R.C. (CCH) ¶ 61,208 (May 13, 1991), and *United Gas Pipe Line Co.*, 46 F.E.R.C. (CCH) ¶ 61,060 (Jan. 24, 1989), modified on other grounds, 49 F.E.R.C. (CCH) ¶ 61,166 (Nov. 7, 1989), followed

Finally, there is no merit to APGA's assertion (96-1187 Pet. 19-20) that the Commission's capacity-release mechanism is merely a sham designed to expand its jurisdiction. As the court of appeals observed, under Order No. 636, "[t]he pipelines' role in capacity release is absolutely central, and the transaction itself controls access to interstate transportation capacity." Pet. App. 84a-85a (footnote omitted). Order No. 636 requires pipelines to maintain electronic bulletin boards upon which proposed transactions are posted, administer the rules for operation of the bidding system, and select the successful bidder. In short, as the court observed, capacity release necessarily involves movement of gas in interstate commerce by the assignee of capacity rights because "[b]y controlling such capacity, the assignors are effectively determining by whom, and under what circumstances, gas will be transported and are using the pipeline's facilities as if they were the assignors' facilities." *Id.* at 81a.

2. Petitioner Burlington Resources Oil & Gas Company (Burlington) (No. 96-1189) argues that the court of appeals erred in affirming FERC's conclusion that pipelines allocating long-term transportation rights under the ROFR mechanism do not have to accept bids at less than the maximum, cost-based just and reasonable rate established by the Commission under the NGA. Burlington asserts (96-1189 Pet. 7-9) that the ROFR rule violates the Commission's obligation under the NGA to protect consumers. As the court of appeals concluded, however, "the basic structure of the [ROFR] mechanism provides

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the *Texas Eastern* approach, and APGA's reliance on those decisions (96-1186 Pet. 14) similarly fails to support the petition.

the [customer] protections from pipeline market power required for pre-granted abandonment under [NGA] § 7." Pet. App. 49a; see also *id.* at 54a-55a. The ROFR procedure "guarantees that existing customers may have continued service," and "affords protection to the existing customer against *any* exercise of monopoly power," *id.* at 933a (emphasis added), because the customer will be required to pay, at most, the cost-based just and reasonable rate established by the Commission in a ratemaking proceeding, *id.* at 679a. As the court of appeals observed, the NGA "protect[s] customers against loss of service only if the customer is willing to pay the maximum rate approved in a rate proceeding." *Id.* at 55a. The Commission concluded that the ROFR mechanism "provides more than adequate protection that pipelines will not be able to charge monopoly rates for their service." *Id.* at 672a. This Court approved a very similar pricing mechanism in *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Cos.*, 498 U.S. 211 (1991) (upholding FERC rule setting maximum "just and reasonable" rate for gas sold under Natural Gas Policy Act price ceilings, but allowing sellers voluntarily to accept lower prices if market conditions dictate).[13]

Contrary to Burlington's assertions (96-1189 Pet. 11-12), FERC's decision to leave to pipelines' discretion whether to accept below-ceiling bids voluntarily does not encourage anti-competitive behavior. The

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[13] If a pipeline elects to leave capacity idle rather than accept a below-ceiling bid for that capacity, the shipper may also file a petition with the Commission under Section 5 of the NGA claiming that the pipeline's action is "unjust, unreasonable, unduly discriminatory, or preferential." 15 U.S.C. 717d(a).

Commission cannot require a pipeline to accept rates below the cost-based just and reasonable rate ceiling under the Commission's ROFR program. Those rates are, by definition, the lowest rates that ensure pipelines an adequate return on their investment; requiring pipelines to accept a lower rate would put them at risk of under-recovery in violation of the Commission's duty to ensure pipelines sufficient returns and adequate capitalization. See *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (rates must "assure confidence in the financial integrity" of the regulated entity "so as to maintain its credit and attract capital"); *Permian Basin Area Rate Cases*, 390 U.S. 747, 792 (1968) (rates must "maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection for the relevant public interests"); *Associated Gas Distribs.* v. *FERC*, 824 F.2d 981, 1007-1013 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988).

Burlington also errs in arguing (96-1189 Pet. 12-15) that FERC should have imposed a rate within the zone of approved rates, but below the maximum just and reasonable rate. Burlington relies chiefly on *Associated Gas*. The pricing mechanism approved in *Associated Gas* established a cost-based just and reasonable rate, but allowed pipelines to "consent to selective discounting" down to prescribed minima. 824 F.2d at 1010. That voluntary discounting approach is precisely the approach taken here.[14]

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[14] Burlington misconstrues cases holding that FERC may establish rates within a "zone of reasonableness." See 96-1189 Pet. 14. That test applies to judicial review of the Commission's rates, not to the establishment of those rates in the first

Finally, Burlington errs in asserting (96-1189 Pet. 18-20) that FERC failed to provide a rationale for its decision not to require pipelines to accept discounted rates under the ROFR process, and that the court of appeals supplied its own rationale. The Commission's statement that pipelines "are not required to accept any offer at less than the maximum rate," Pet. App. 673a, correctly reflects existing law on that point. See page 22, *supra*. Each of the rationales relied upon by the court of appeals was also articulated in the Commission's orders. See Pet. App. 671a-673a, 935a-937a. In any event, a reviewing court retains the power to identify the proper construction of the governing law, even if not argued by the Commission. *Arcadia* v. *Ohio Power Co.*, 498 U.S. 73, 77 (1990).

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instance. See *Permian Basin*, 390 U.S. at 767. Burlington also asserts (96-1189 Pet. 16) that the NGA does not guarantee pipelines cost recovery, but only affords them the opportunity to recover their costs. That opportunity, however, must include the possibility of recovering adequate returns on capital investment, which, by definition, turns on the cost-based rate established by the Commission.

CONCLUSION

The petitions for a writ of certiorari should be denied.

Respectfully submitted.

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IN THE
Supreme Court of the United States
OCTOBER TERM, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,
Petitioners,
v.
FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

REPLY OF PETITIONERS ASSOCIATED GAS DISTRIBUTORS, ATLANTA GAS LIGHT COMPANY, CHATTANOOGA GAS COMPANY, AND NORTHERN INDIANA PUBLIC SERVICE COMPANY

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1. This Court recently reaffirmed that one of the central premises underlying the Natural Gas Act was Congress' desire to preserve for the States their "traditional autonomy to authorize and regulate local gas franchises." *General Motors Corp. v. Tracy*, —— U.S. ——, 1997 U.S. LEXIS 692 (Feb. 18, 1997), slip op. at 29. *See generally* slip op. at 23-34. This Court observed that Congress had reaffirmed that premise with the Hinshaw Amendment (codified at 15 U.S.C. § 717(c)). Reacting to the decision in *East Ohio Gas*,[1]

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[1] *Federal Power Comm'n v. East Ohio Gas Co.*, 338 U.S. 464 (1950).

> Congress amended the NGA to "leave jurisdiction" over "companies engaged in the distribution" of natural gas "exclusively in the States as always has been intended."

Slip op. at 28, *quoting* S. Rep. No. 817, 83d Cong., 1st Sess., 1-2 (1953). Under the terms of this grant of authority to regulate LDCs, "all 50 States recognize the need to regulate utilities engaged in local distribution of natural gas," and have typically imposed upon LDCs comprehensive obligations and restrictions reflecting state policy. Slip. op at 30-34.

2. The NGA thus contemplated two complementary, not overlapping, spheres of authority, one state and one federal. To the extent the States were assigned authority—as they were, under Section 1(c) to regulate LDC in-state sales—FERC has no authority to regulate. Because FERC has no authority to regulate in the area assigned to the States, it cannot preempt state regulation.

3. In issuing Order 636, FERC paid no heed to the grant of exclusive authority to the States in NGA Section 1(c), 15 U.S.C. § 717(c). Rather, it deemed it sufficient that FERC possessed an arguable basis for exercising authority to regulate the transactions in question under the language of NGA Section 1(b), 15 U.S.C. § 717(b).

Likewise, the Court of Appeals failed to address either the scope of state authority under NGA Section 1(c) or the significance of Congress' decision to preserve for the States a sphere of regulatory control free from federal intrusion. Instead, the lower court focused singularly on the language of Section 1(b) affirmatively describing the scope of FERC jurisdiction. In this way, it treated the apparent grant of authority to the States under Section 1(b) as merely the residuum of whatever was left over after construing the scope of federal agency power. It then went on, summarily, to treat Section 1(c) the same way, despite the fact that Section 1(c), by its terms, creates a sphere of authority "exempted" from the exercise

of federal authority. 15 U.S.C. § 717(c). The Court of Appeals' analysis thus did not take into account in any way the important state interests reflected in the NGA, and now highlighted in *General Motors Corp. v. Tracy*.

As shown in AGD's Petition, this was error, for it turns the state-federal structure of the NGA on its head. The Court of Appeals' analysis is improperly skewed in favor of a broad federal authority that can run roughshod over the state interests *expressly* protected by the NGA. *See* AGD Petition at 13-24.

4. Nonetheless, FERC's brief in opposition takes the same tack. It emphasizes FERC's asserted interest here in creating "uniformity" and highlights cases upholding FERC's authority over the "transportation of natural gas in interstate commerce." FERC Brief in Opposition at 10. In so arguing, FERC sidesteps the fact that NGA Section 1(c) is an exemption, and thus a limitation, on federal power—the effect of which was never addressed by FERC in Order 636, or by the Court of Appeals.[2] Indeed, only in passing does FERC here acknowledge that its so-called "plenary" transportation jurisdiction does *not* extend to transactions "which Congress has made explicitly subject to regulation by the States." FERC Br. in Opposition at 10, *quoting FPC v. Southern California Edison Co.*, 376 U.S. 205, 216 (1964).

5. As shown in the Petition, NGA Section 1(c), by its plain language, provides for exclusive state jurisdiction over (and federal authority "shall not apply to") "any person" coming within its terms, notably LDCs engaged in providing gas to be consumed within the State. 15 U.S.C. § 717(c). Thus, the NGA contemplates comprehensive state regulatory authority over LDCs in their relations with in-state customers. In its brief in opposition,

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[2] "To permit an agency to expand its power in the face of a congressional limitation on its jurisdiction would be to grant to the agency power to override Congress." *Louisiana Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374-75 (1986).

FERC argues about whether an LDC's sale of capacity rights to its in-state customer qualifies as "local distribution" under *Section 1(b)*. FERC Br. in Opposition at 13. But FERC offers no interpretation of the language of *Section 1(c)* that would somehow avoid the exclusive authority that the States exercise over LDCs and their local facilities in connection with gas consumed within the State.

6. FERC does assert that for Section 1(c) to apply, the "service at issue would have to be subject to *effective state regulation*." FERC Br. in Opposition at 16. FERC then defines "effective" in terms of the States' inability to "prevent interstate pipelines from discriminating in favor of in-state users at the expense of out-of-state users." *Id.*

Contrary to FERC's suggestion, Section 1(c) does not specify "effective state regulation." It requires merely "that the rates and service of such person *be subject to regulation* by a State commission." 15 U.S.C. § 717(c).[3]

Moreover, judging "effectiveness" on the basis of whether the States can prevent "interstate pipelines" from discriminating, defines the test in a way that it can never

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[3] FERC does not suggest that States have not, in fact, regulated capacity sales by LDCs to in-state customers. FERC's quibble turns on its addition of the word "effective."

Examples of state regulation over LDC capacity sales were cited in AGD's Petition at 10 n.4. As it affects capacity sales, these examples show that the States have established (a) processes for allocating LDC surplus pipeline capacity rights among industrial customers that have acquired their own "unbundled" gas supply; and (b) rate regulation to control both amounts paid by local end users for pipeline capacity rights acquired from LDCs *and* the disposition of the revenue from such transactions for the benefit of captive consumers.

Order 636, of course, preempts most of these state regulatory measures by imposing a federal procedure for LDCs' allocation of capacity among local consumers *and* federal rate regulation to fix the maximum amount an LDC may collect from those customers for this service.

be met: The States have no jurisdiction over "interstate pipelines" generally. Their jurisdiction is over LDCs and LDC service to in-state customers, including pipeline capacity that the LDCs would continue to use for service to their in-state customers. By its nature, state regulation can only address "in-state users" and, of necessity, cannot address discriminations between "in-state" and "out-of-state" users. Indeed, by assigning regulatory authority to the States, Congress necessarily gave precedence to the States' interest in regulating in-state uses over whatever benefits—in terms of national uniformity and prevention of discrimination between in-state and out-of-state users—might have flowed from a plenary grant of authority to FERC over *all* aspects of the natural gas market. It is inherent in the NGA that sometimes these federal interests must give way.

7. As the Court recounted in *General Motors Corp.*, regulatory developments, encouraging the "unbundling" of gas sales, have changed certain marketing practices in the gas industry. They have prompted the precise situation addressed here, where an LDC seeks to service its in-state customer, not with bundled gas, but by sale of firm pipeline capacity needed by the in-state customer. Though this restructuring of the industry would expectably produce some disharmony in the fit between market structure and the NGA provisions preserving traditional state authority, the language of Section 1(c) still rings true. Moreover, the basic intent of that provision, to provide for exclusive state authority over the relationship between LDCs and their customers—clearly subject to state regulation—is undiminished by these changes in the structure of the market. The authority of the States, and the purpose of these provisions preserving state authority, cannot simply be ignored. Yet that is exactly what both FERC and the Court of Appeals did in upholding Order 636. The result fundamentally undermines the States' comprehensive regulatory control over LDCs' service to in-state customers.

Given Congress' express reservation of power to the States, FERC's exercise of power, disrupting the regulatory scheme applicable to natural gas service in all 50 States, presents an issue of fundamental importance. In light of the federal circuit court's decision to ignore these state interests under the NGA, it is incumbent upon this Court to ensure that the interest of the States is both respected and reflected in the federal regulatory scheme.

CONCLUSION

The petition for issuance of a writ of certiorari should be granted.

Respectfully submitted,

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